151.

3C
SKD
SKD/KKS
BC/RVD/JM
SI/DA
LYK/WT

FILED

2007 AUG -6 P 3:03

PUBLIC UTILITIES COMMISSION

BEFORE THE

PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	DOCKET NO. 2006-0386
	)	
For Approval of Rate Increases and Revised Rate Schedules and Rules	)	

TESTIMONY OF

RALPH C. SMITH, CPA

ON BEHALF OF

THE DEPARTMENT OF DEFENSE

AND

CERTIFICATE OF SERVICE

RANDALL Y.K. YOUNG
Associate Counsel (Code 09C)
Naval Facilities Engineering Command, Pacific
258 Makalapa Drive, Suite 100
Pearl Harbor, HI 96860-3134
Telephone (808) 472-1195

ATTORNEY FOR
DEPARTMENT OF DEFENSE

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	
	)	Docket No. 2006-0386
For Approval of Rate Increases and	)	
Revised Rate Schedules and Rules	)	
	)	

TESTIMONY OF

RALPH C. SMITH, CPA

ON BEHALF OF

THE DEPARTMENT OF DEFENSE

Filed August 6, 2007

TESTIMONY OF
RALPH C. SMITH, CPA
ON BEHALF OF
THE DEPARTMENT OF DEFENSE

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

Q. What is your occupation?

A. I am a certified public accountant and a senior regulatory utility consultant with the firm Larkin & Associates, PLLC, certified public accountants and regulatory consultants.

Q. What is your educational background and professional experience?

A. These are presented as Exhibit DOD-100. This exhibit also summarizes some of my regulatory experience and qualifications.

Q. On whose behalf are you appearing?

A. My firm is under contract with the Navy Utility Rate and Studies Office (URASO) to perform utility revenue requirement studies. The Navy represents the Department of Defense (DOD) in Hawaii.

Q. Please describe the tasks you performed related to your testimony in this case.

A. We reviewed and analyzed data and performed other procedures as necessary (1) to obtain an understanding of the Hawaiian Electric Company Inc.'s ("HECO" or "Company") rate filing package as it relates to the operating income, rate base, and overall revenue requirement in this case and (2) to formulate an opinion concerning the reasonableness of amounts included within the Company's application for rate increase.

These procedures included reviewing the Company's testimony, exhibits and workpapers, issuing information requests, and analyzing HECO's responses to them.

Q. Have you prepared exhibits to present in support of your testimony?
A. Yes. I have prepared Exhibits DOD-101 through DOD-122.

Q. Were these exhibits prepared by you or under your supervision?
A. Yes, and they are correct to the best of my knowledge and belief.

Q. What issues will you be addressing in your testimony?
A. My direct testimony discusses the development of DOD's recommended adjustments to HECO's rate base, net operating income, and revenue requirement.

Q. Has HECO updated and/or revised its rate filing?
A. Yes. HECO has supplied updates in a series of letters and attachments.

Q. What amount of increased revenues is HECO seeking in this case?
A. HECO's direct filing, as summarized in HECO T-23, on pages 1 and 2, requested a rate increase of $99.556 million at "current effective" rates or $151.505 million at "present" rates. HECO's "current effective rates" included a 4.36% increase from the Commission's Interim Decision and Order No. 22050

in Docket No. 04-0113, HECO's rate case for test year 2005. HECO T-23, at page 2, directly attributes the difference of $51.949 million in revenues between present and current effective rates to the 2005 Rate Case Interim surcharge revenues.

Q. Has HECO revised its calculated revenue deficiency?

A. Yes. HECO filed its "June 2007 Update" for HECO T-23 on July 24, 2007, which contained recalculations of the Company's revenue deficiency. HECO-2301 as "updated" by HECO now shows a revenue deficiency at "current effective rates" of $97.320 million and HECO-2302 now shows a revenue deficiency at "present rates" of $152.824 million.

Q. What impact on HECO's calculated amounts of revenue deficiency did the Company's "June 2007 updates" have?

A. This is summarized in the following table:

Revenue Requirement Calculated by HECO	At "Current		At	
(Thousands of Dollars)	Effective Rates"		"Present Rates"	
	HECO-2301		HECO-2302	
Proposed revenue deficiency, as filed by HECO	$	99,556	$	151,505
Calculated revenue deficiency per 7/24/07 "June 2007 Update"	$	97,320	$	152,824
Impact of HECO's Updates, increase (decrease)	$	(2,236)	$	1,319

Q. What starting point did you utilize in determining HECO's 2005 rate base and net operating income?

A. I used HECO's originally filed rate base and net operating income as my starting point and have reflected my recommendations as adjustments to HECO's original filing.

Q. How have you dealt with HECO's updates in your testimony?

A. Where the reasons for HECO's updates were clear and the impacts were clearly quantified and/or confirmed in HECO's responses to DOD IRs, I reflected the Company's revised amounts in my adjustments on DOD-107 for rate base changes and DOD-112 for net operating income changes. I should caution, however, that reflecting HECO's updates in this manner should not be interpreted or implied as an endorsement or agreement with every aspect of what HECO adjusted in its updates.

II. REVENUE REQUIREMENT/SUMMARY SCHEDULES

Q. What revenue requirement impact is produced by DOD's recommended adjustments?

A. DOD-101 summarizes and presents the estimated impact on revenue requirements resulting from DOD's recommended adjustments to operating income and rate base that have been quantified as of the date of this filing. It also reflects the weighted cost of capital recommended by DOD witness Stephen Hill. Based on DOD's recommended adjustments, HECO has a revenue deficiency of no more than $55 million.

Q. Please explain DOD-101, page 1.

A. Column A reproduces in summary form, HECO's originally filed request for a revenue increase of $151.505 million "at present rates" from information presented on HECO-2302 and the underlying workpapers. Column B shows the DOD's adjusted results. Column C shows the dollar impacts of DOD's recommended adjustments to each line item of the revenue requirement formula.

In columns A and B, adjusted rate base on line 1 is multiplied by the recommended rate of return (on line 2) to determine the required amount of net operating income (line 3). The required net operating income (line 3) is compared with the adjusted net operating income (line 4) to determine the income deficiency (line 5). The operating income deficiency (line 5) is then multiplied by the gross revenue conversion factor (line 6) to determine the revenue deficiency (line 7). In column A, there is a minor reconciling difference of $12,000 to derive HECO's original filed revenue deficiency amount of $151.505 million. Column A also shows the impacts of HECO's June 2007 updates, and reconciles to HECO's revised updated revenue deficiency at "current effective rates" of $97.320 million.

Q. Please explain DOD-101, page 2.

A. This page of the DOD-101 reconciles the revenue deficiency requested by HECO with the revenue deficiency recommended by DOD. DOD-101, page 2, starts with HECO's filed revenue increase of $151.505 million at present rates from and shows the impact of each DOD adjustment, culminating in DOD's calculated revenue deficiency of approximately $55 million. For ease of reference, these results are also presented in summarized format in the following table:

Summary of Differences Between DOD and HECO ($000)

Description	Reference	Adjustment Amount	Revenue Requirement Amount [DOD-101, p.2]
Revenue Requirement-per HECO Filing (HECO-2301)	DOD-101,L.9		$ 151,505
Rate of Return Difference on HECO rate base	DOD-101,p2		$ (26,756)
Rate Base Adjustments		**DOD-106**	
HECO June 2007 update	DOD-107	$ (13,100)	$ (1,813)
Remove Net Pension Asset	DOD-108	$ (36,291)	$ (5,023)
Cash Working Capital	DOD-109	$ (7,000)	$ (969)
Accumulated Deferred Income Taxes	DOD-110	$ (8,157)	$ (1,129)
Change in Working Cash at Proposed Rates	DOD-109	$ 956	$ 153
Net Operating Income Adjustments		**DOD-111**	
HECO June and July 2007 Updates	DOD-112	$ (2,093)	$ 3,763
Revenues; Known Rate Changes	DOD-113	$ 31,859	$ (57,282)
Remove Amortization of Pension Asset	DOD-114	$ 3,088	$ (5,552)
Edison Electric Institute Expense	DOD-115	$ 37	$ (67)
Security Services Expense	DOD-116	$ 71	$ (128)
"Community Process" Expenses	DOD-117	$ 202	$ (363)
Income Taxes - Interest Synchronization	DOD-118	$ 587	$ (1,055)
Research, Development and Demonstration Exp.	DOD-122	$ 229	$ (411)
Reconciled Revenue Requirement	DOD-101,p2		$ 54,873
Unreconciled Difference	DOD-101,p2		$ 86
Recommended Revenue Requirement	DOD-101,p1		$ 54,959

Q. What is presented on DOD-102?

A. This presents the calculation of the gross revenue conversion factor (GRCF). I am recommending a GRCF of 1.797979. The GRCF is used to convert net operating income amounts into revenue requirement amounts, and is used on DOD-101, page 1, line 6, for this purpose. It is also used on DOD-101, page 2, to convert net operating income adjustments into their revenue requirement equivalent.

Q. Please explain DOD-103.

A. DOD-103 summarizes the adjusted rate base. HECO's original filed amounts from the HECO-2302 workpapers are shown in Column A. Column B summarizes the DOD adjustments to each rate base component, and column C shows the adjusted results. As shown on DOD-103, the adjusted rate base for HECO is approximately $1.151 billion.

Q. Please explain DOD-104.

A. DOD-104 summarizes the adjusted net operating income. HECO's original filed amounts are shown in Column A. Column B summarizes the DOD adjustments to each operating income component, and column C shows the adjusted results. As shown on DOD-104, the adjusted net operating income for HECO at currently effective rates is 58.038 million.

Q. Please explain DOD-105.

A. DOD-105 summarizes HECO's originally filed proposed capital structure and weighted cost of capital in Part I and DOD's recommended capital structure and weighted cost of capital in Part II. DOD's cost of capital recommendations produce an overall weighted cost of capital of 7.70% and are being sponsored by Stephen G. Hill. I calculated the "Pre-Tax Rates" shown in DOD-105, column D. I used such rates for purposes of reconciling the DOD and HECO revenue requirements on DOD-101, page 2.

III. RATE BASE ADJUSTMENTS

Q. Have you prepared an exhibit that summarizes DOD's adjustments to rate base?

A. Yes. These adjustments are shown on DOD-106. The recommended adjustments to rate base are discussed in the same order as they appear on

DOD-106.

A. *HECO June 2007 Rate Base Update*

Q. How have you reflected the rate base changes identified in HECO's June 2007 updates?

A. DOD-107 shows the adjustment to reduce rate base by $13.1 million for the cumulative impact of HECO's June 2007 updates. As shown in the response to DOD-IR-96, as a result of its updates, HECO is proposing a rate base of $1,201,212,000.

Q. Should your reflection of HECO's updates to rate base shown on DOD-107 be interpreted as an endorsement of all of HECO's updates?

A. No, it should not. Reflecting the HECO updates in the manner shown on DOD-107 is intended to adjust the starting point of my rate base analysis to what HECO has proposed. Reflecting HECO's updates in this manner was administratively efficient and should not be interpreted or implied as an endorsement or agreement with every aspect of what HECO adjusted in its updates.

B. *Pension Asset*

Q. Do you agree with HECO's proposed inclusion in rate base of an amount for Prepaid Pension Asset?

A. No. Whether or not HECO should be allowed to include a pension asset in rate base was extensively discussed in HECO's prior rate case, Docket No. 04-0113. As in that case, in the current case HECO has similarly failed to demonstrate that investors have funded the pension asset. My analysis, which is shown on DOD-108 page 2, shows that the cumulative amounts of pension cost reflected in rates from 1996 through 2007 have resulted in ratepayers effectively "funding" (even "over-funding") HECO's pension asset by approximately $47 million. Based on such analysis, it would be inappropriate to charge ratepayers for an additional return on HECO's pension asset by including it in rate base. I therefore recommend that HECO's pension asset be removed from rate base.

Q. Please explain the adjustment on DOD-108.

A. This adjustment reduces rate base by $36.291 million for the removal of HECO's updated pension asset of $59.405 million less related accumulated deferred income taxes of $23.114 million.

Q. Has HECO demonstrated that its investors have funded an average 2007 test year pension asset of $59.405 million?

A. No. HECO has not demonstrated that investors have funded the pension asset. HECO refers to the results of applying Statement of Financial Accounting Standards No. 87 (FAS 87) as "net periodic pension cost" or "NPPC." HECO T-10, starting at page 79, presents HECO's reasoning for why the Company believes that the pension asset has been funded by investors.

Q. Do you agree with HECO that its pension asset was funded by investors?

A. No. My analysis, which is shown on DOD-108, page 2 of 2, line 27 shows that ratepayers have provided approximately $47 million to HECO related to pensions during the period 1996 through 2007. As shown on DOD-108, page 2, I have performed a similar analysis to the one I presented in HECO's last rate case, Docket No. 04-0113, and have updated it for more current information.

Q. How did you update your analysis from HECO's prior rate case, Docket No. 04-0113, for purposes of evaluating, in HECO's current rate case, whether ratepayers or investors have funded HECO's average 2007 pension asset?

A. As shown on DOD-108, page 2, column B, line 23, for the period 1996 through 2005 (the test year in HECO's last rate case), HECO recorded <u>negative</u> pension costs of approximately $30.2 million. The logical conclusion is that the $30.2 million of <u>negative</u> pension cost that HECO recorded from 1996-2005 was <u>not</u> provided to ratepayers, i.e., ratepayers were not given "credit" for this <u>negative</u> pension cost and it was not refunded by HECO to ratepayers, but rather the large net <u>negative</u> pension cost for this period increased net income to the benefit of HECO's investors.

In a rate case the amount to be provided annually by ratepayers for pensions as part of a total revenue requirement might be based upon the NPPC in the test year. In between rate cases, the annual NPPC can fluctuate significantly and substantial decreases in pension cost between rate cases tend to inure to shareholders, not ratepayers. HECO did not re-establish base rates through a rate case during this period, other than for the Interim rate adjustment made in Docket No. 04-0113, which recognized an annualized NPPC amount of $4.588 million for ratemaking purposes. As shown on DOD-108, page 2, column B, line 24, HECO's FAS 87 accruals for the period 1996 through 2007 accumulate to net periodic pension costs of only $1.735 million.

As shown in column F, the NPPC included in HECO's ratemaking for the period 1996 through 2007 totaled approximately $98.286 million.

As shown on line 25, the amount "provided" by ratepayers during 1996 through 2007 for pension cost was approximately $96.551 million ($98.286 million NPPC included in HECO's rates from column F, less the net amount of SFAS 87 pension accruals of $1.735 million from column B). In comparison with the pension funding contributions of $49.635 million that HECO made (from column C), the $96.551 million provided by ratepayers exceeds such Company funding contributions by $46.916 million, as shown on line 27. Thus, ratepayers have provided approximately $47 million for pension cost than HECO has paid for funding contributions into the pension trust for the period 1996 through 2007.

Such a significant mismatch between the NPPC in rates paid by ratepayers and HECO's actual expenses and funding payments is contrary to HECO's claim that the pension asset existing in the 2007 test year has been funded by investors.

Q. Your analysis has focused on contributions to the trust fund, the net periodic pension cost, and the amount of pension cost included in rates since 1995, yet DOD-108, page 2, also lists amounts for prior years. Please explain why you have focused your analysis on such amounts since 1995.

A. The cumulative contributions to the trust fund and the cumulative net periodic pension costs net to zero for the period prior to 1996, and therefore do not affect the 2007 test year. As HECO has conceded in its response to DOD-IR-

107(d):

> "Contributions to the trust fund and the net period pension cost since the inception of SFAS 87 were provided. The amounts prior to 1995 are for informational purposes only. Because the cumulative contributions to the trust fund and the cumulative net periodic pension costs net to zero in the period prior to 1996, the amounts do not impact the 2007 test year."

Q What does your analysis show, since the 1995 test year rate case, regarding the total level of ratepayer contributions toward pension expense versus HECO's contributions?

A. As shown on DOD-108, page 2, my analysis shows that ratepayers have "provided" at least $96.550 million (represented by the difference between what ratepayers paid and what HECO recorded as NPPC) to HECO for Pension expense from 1996 through 2007, while HECO recorded a net SFAS 87 pension cost of $1.735 million and deposited $49.635 million into the Pension Trust for the same period. Thus, as noted above, ratepayers have provided HECO with a net amount of approximately $46.916 million for pension cost, as shown on DOD-108, line 27, during the relevant period of 1996 through 2007. Given these results, it would be extremely inequitable to HECO's ratepayers to allow inclusion of a $59.405 million pension asset in rate base in the current rate case.

C. *Cash Working Capital*

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is an increase to rate base as investors are essentially supplying these funds.

Q. Does HECO have a positive or negative cash working capital requirement?

A. HECO's filing shows a positive cash working capital requirement. This result implies that , on average, revenues from ratepayers are received after the utility pays the associated expenditures.

Q. Did HECO present a lead/lag study in support of its cash working capital requirement?

A. Yes, HECO provided lead/lag study information to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with the work papers provided in the case.

Q. Are there concerns regarding how HECO has treated certain items in its cash working capital calculation?

A. Yes. I address such concerns below, and present the adjusted cash working capital on DOD-109. My presentation uses the same format for determining cash working capital that was used on HECO-1706.

1. Pension Asset Amortization

Q. Please comment on the proposal by HECO to include amortization of a pension asset in the determination of cash working capital at a zero payment lag.

A. This proposal by HECO should be rejected in total for the following reasons:

First, non-cash expenses, such as depreciation and deferred income taxes, should be excluded from the determination of cash working capital. The objective of the lead lag study is to determine the amount by which ratepayers or investors are funding the utility's <u>cash</u> working capital requirement. Consequently, non-cash expenses, such as depreciation, are excluded. The Commission precedent and practice has been to exclude non-cash items. Similarly, the amortization of the estimated December 31, 2007 pension asset balance proposed by HECO is <u>not</u> a cash expense, and it should therefore be excluded from cash working capital.

Second, the inclusion of pension asset amortization in the determination of cash working capital is inconsistent with HECO's direct testimony and with the six cash expense items that were allowed for cash working capital in prior HECO cases.

Q. How is the inclusion of pension asset amortization in the determination of cash working capital inconsistent with HECO's direct testimony and with the six cash expense items that were allowed for cash working capital in prior HECO cases?

A. HECO's direct testimony at T-17, pages 19-20, listed the six items that are included in the payment lag. These six items were based on what the Commission had allowed in previous decisions regarding the determination of cash working capital. As stated in the response to DOD-IR-98(d), HECO had never included an amortization of a pension asset in a prior rate case. At page 20 of HECO T-17, the Company states: "Limiting the working cash needs to these six categories of payments is consistent with the HECO 1995 Decision. It is also consistent with the HECO 2005 Interim Decision." HECO's attempt in its June 2007 update to add a new seventh item – amortization of a pension asset – into the cash working capital determination is inconsistent with HECO's direct testimony and prior cases cited by HECO. Therefore, it is improper and should be rejected for the reasons identified above.

2. Pension Funding Payment Lag Days

Q. What payment lag did HECO assume for its annual 2007 pension expense?

A. Per DOD-IR-100, page 9 of 10, HECO assumed a 14-day payment lag for pension expense.

Q. Is 14 days an appropriate lag for HECO's annual 2007 pension expense?

A. No. HECO's assumed payment lag appears to be far too short and fails to reflect the Company's actual pattern of pension funding contributions in the most recent three years, 2005 through 2007, or its anticipated funding for the 2007 NPPC. HECO has made funding contributions into the pension trust, e.g., in 2005, so near the end of the calendar year. HECO's assumption of a 14-day payment lag would be appropriate only if HECO had been funding its 2007 NPPC on a monthly basis. Assuming funding of one-twelfth of the annual amount at the end of each month would imply a payment lag of approximately 15.2 days (365 days / 12 months / 2 for average period in the month). If HECO had been making monthly pension funding payments of 1/12th of its estimated annual 2007 NPPC in 2007, and such payments were made a day or two before month-end, a 14-day pension payment lag would be appropriate. However, HECO has not done that.

Q. What amounts of pension funding did HECO make to the pension trust in 2005, 2006 and 2007?

A. Per the response to DOD-IR-110 and CA-IR-140, HECO made a funding contribution of $6 million on December 29, 2005. HECO did not make any contributions to the pension plan in 2006 and none in 2007.

Q. Did HECO have a pension funding study conducted for it?

A. Yes. A copy of HECO's pension funding study conducted by Watson Wyatt was provided.

Q. What did the pension funding study indicate in terms of "short term funding considerations"?

A. Short-term funding considerations were presented at pages 67-68 of the Watson Wyatt pension funding study. As explained in the response to DOD-IR-118(g): "For HECO, as of January 1, 2007, the plan is over 100% funded on a current liability basis, so there is no special short-term funding consideration needed for the plan to avoid adverse circumstances with regard to funding requirements under the Pension Protection Act. HECO will generally be targeting the third block on the slide, primarily because HECO is generally at that level." That target is for 90% funded status for 2007 and 92% funding for 2008. The "fourth block" on the referenced page is to "contribute [the] maximum deductible contribution in 2006 and 2007."

Q. Could HECO have made tax-deductible pension funding contributions in amounts equal to or greater than its NPPC in each year, 2005, 2006 and 2007?

A. Yes. HECO's response to DOD-IR-107(e) lists the maximum tax deductible contributions for 1999-2007. The maximum tax deductible contributions for 2005 through 2007 are shown in the following table, with the corresponding annual amount of HECO's NPPC and the annual amount of HECO's pension funding contribution shown for comparison:

Year	Maximum Tax-Deductible Pension Funding Contribution	Net Period Pension Cost DOD-108,p.2	Actual Pension Funding Contribution DOD-108,p.2
2005	$ 76,324,682	$ 4,588,000	$ 6,000,000
2006	$ 37,035,984	$ 14,237,000	$ -
2007	$ 75,356,124	$ 17,711,000	$ -

Q. What does this information indicate in terms of the pension funding lag?

A. This indicates that the pension funding payment lag for the 2007 NPPC is longer than the 14 days assumed by HECO in its lead-lag study. For example, if HECO were to fund the $17.711 million 2007 NPPC on December 31, 2007, the funding payment lag would be 182.5 days (365/2). If a funding payment for the 2007 NPPC were to be remitted by HECO beyond December 31, 2007, the funding lag would be longer.

Q. What has HECO stated with respect to how its pension funding would be impacted by whether a "pension tracking mechanism" is adopted?

A. HECO's response to DOD-IR-113(i) states: "The Company does not foresee any change in its pension funding policy resulting solely from the determination of whether the pension tracking mechanism is adopted or not."

Q. What lag did you apply for 2007 pension expense?

A. I applied a lag of 182.5 days. As explained above, HECO has not contributed any amounts to the pension fund in 2006 and projects no pension funding payment for 2007. As noted above, although HECO has not made a payment into the pension trust for 2007 yet, and projects not making one, HECO nevertheless could make a tax-deductible contribution for the full annual 2007 amount of pension expense. The 182.5 day lag is conservative, in that it assumes that the lower of the 2007 NPPC or the 2007 maximum tax-deductible funding contribution would be funded by a payment to the pension trust by December 31, 2007. .

3. Amortizations/Expense Normalizations

Q. How did HECO reflect amortizations/expense normalizations in deriving its proposed payment lag?

A. As stated in HECO's response to DOD-IR-100, on page 2 of 10, "these amortization items were not separately identified in calculating the O&M non-labor payment lag previously." However, as described in the response to DOD-100, and shown on page 9 of 10 of that response, HECO would now propose to reflect various amortizations at a zero payment lag. While HECO continues to use a 32-day payment lag for non-labor O&M expense in its update, it has provided a "refined calculation" including amortizations at a zero payment lag, including rate case expense at a negative 731-day payment lag. As shown on DOD-IR-100, page 9 of 10, HECO's new calculation would result in an O&M non-labor payment lag of 30 days.

Q. Do you agree, in general, with the inclusion of such amortizations in the lead-lag study at a zero day lag?

A. No. Inclusion of amortizations in a lead-lag study at a zero-day payment lag is generally improper because amortization is a non-cash expense, and the purpose of a lead-lag study is to determine the utility's <u>cash</u> working capital requirement.

Q. In general, how should the payment lag for amortizations be determined for purposes of the cash working capital requirement?

A. This depends upon the purpose of the amortization. If the purpose of the amortization is to adjust an O&M expense to a normalized level for ratemaking purposes, then the normal payment lag applicable for other similar O&M non-labor expense should be applied. If the purpose of the amortization is to include a non-cash expense in the determination of net operating income, it should be excluded from the lead-lag study, similar to the exclusion of non-cash expenses such as depreciation and deferred income taxes. As noted above, because the purpose of the lead-lag study is to measure <u>cash</u> working capital, non-cash expenses are excluded.

Q. How were the amortizations treated for ratemaking purposes in prior cases?

A. This is discussed in HECO's response to DOD-IR-100.

Q. How have you adjusted the amortizations listed by HECO on DOD-IR-100, page 9 of 10?

A. I have removed such items from the derivation of the O&M non-labor payment lag, as shown on DOD-.109, page 2.

4. Rate Case Expense

Q. How has HECO proposed to treat rate case expense in its lead-lag study?

A. As explained in the response to DOD-IR-100, page 4, HECO proposes to include rate case expense in the lead-lag study at a negative 731-day payment lag.

Q. Do you agree with that treatment?

A. No. Reflecting rate case expense in the determination of cash working capital at a negative 731-day lag is another way, albeit more indirect, of the utility attempting to include rate case expense in rate base to earn a return for its shareholders. Reflecting rate case expense in the lead-lag study at a negative 731-day payment lag would essentially be equivalent to including the unamortized balance of rate case expense in rate base, to earn a return for investors. Unamortized rate case expense should not be included in rate base either directly, or indirectly by including it in the cash working capital determination at a 731-day negative payment lag. Allowing HECO to earn a rate of return on rate case cost would be contrary to public policy and commission precedent. Rate case expense is a standard cost of doing business for a utility. It is an operating expense. There is no reason that the shareholders should earn a return on rate case expense. Allowing HECO to earn a profit on its rate case expense could also encourage the Company to incur higher amounts of such expense.

Q. How did you reflect rate case expense in the determination of the non-labor O&M expense lag?

A. In order to avoid indirect inclusion of the unamortized balance of rate case cost in rate base, but to recognize the non-labor O&M payment lag applied to the rate case expenditures, I have applied the normal non-labor O&M payment lag of 30 days for this item in the determination of the non-labor O&M lag. As explained above, HECO's proposal to include it in the lead-lag study at a 731-day <u>negative</u> payment lag is improper for a number of reasons and should be rejected.

Q. What is your total non-labor O&M payment lag, after reflecting the above adjustments?

A. It is 50 days as shown on DOD-109, page 2.

5. Annual Expense Amounts

Q. How did you derive the annual expense amounts shown in DOD-109, page 1, Column D?

A. The derivation of the adjusted annual expense amounts in DOD-109, Column D is shown on lines 14-20 of the exhibit. DOD-109, column I, begins with the adjusted expense amounts used by the Company in its June 2007 update version of the cash working capital calculation, as shown on DOD-IR-97, page 2 of 3. Columns J through N show the impact of DOD adjustments and the adjusted results at present and proposed rates for each category of expenses that is used in the working cash calculation.

Q. What are the net results of your cash working capital recommendations?

A. As shown on DOD-109, line 9, columns F and H, respectively, the results of my cash working capital calculations are an allowance of approximately $19.3 million at present rates and $18.7 million at proposed rates.

Q. Do you have any other recommendations concerning cash working capital?

A. Yes. As explained in the response to DOD-IR-100(d), in D&O No. 8570 (12/12/85) in Docket No. 5081, HECO's test year 1985 rate case, and in D&O 10993 (3/6/91) in HECO's test year 1990 rate case, the Commission addressed the exclusion of non-cash expenses such as depreciation and deferred income tax expense from the calculation of cash working capital. Despite such decisions, HECO states on DOD-IR-100, page 2 of 10, that its "position" is that <u>all</u> revenues should be included in the revenue collection lag and all payments should be included in the payment lag in the calculation of cash working capital. Given the apparently growing areas of disagreement regarding the appropriate treatment of various items for lead-lag study/cash working capital purposes that have become apparent from some of HECO's recent responses to discovery, such as DOD-IR-100, I recommend that cash working capital be comprehensively reviewed in HECO's next rate case. This review should include a re-examination of ratepayer provided funding for other cash expenditures that are included in the determination of HECO's revenue requirement, including interest expense.

D. Accumulated Deferred Income Taxes for "AFUDC in CWIP"

Q. Please explain your adjustment for Accumulated Deferred Income Taxes (ADIT).

A. This adjustment restores the rate base reduction for the ADIT related to "AFUDC in CWIP." As shown on Exhibit DOD-110, rate base is reduced by $8.157 million to reflect the average 2007 test year amount of ADIT related to "AFUDC in CWIP" in rate base. This is derived from HECO's June 2007 update for HECO T-15 supplemental filing, pages 16-19.

HECO reduced the ADIT balance for "AFUDC on CWIP" based on the following explanation, from CA-IR-305:

> "AFUDC in CWIP
>
> Construction work in progress ("CWIP") is excluded from rate base and has been excluded consistently in prior rate proceedings. As discussed on pages 2 and 3 of Ms. Ohashi's testimony at T-17 in Docket No. 2006-0386, CWIP is not an included item for rate base purposes. This treatment is consistent with her presentation in Docket No. 04-0113, for which interim D&O No. 22050 was issued and with the rate base methodology used by the Commission in its D&O No. 14412 (December 11, 1995) in Docket No. 7766. Allowance for funds used during construction ("AFUDC") is accrued on CWIP balances for the cost of financing assets during construction. The Company includes the invested cost (including AFUDC) in rate base when the assets are placed into service and begins depreciation of the cost (including AFUDC) in the year following the completion of the assets.
>
> AFUDC is ignored for tax purposes and is neither taxable income nor part of depreciable tax basis of the asset. Consequently, deferred income taxes are provided on the amount of AFUDC incurred and recognized as income for book purposes but not for tax purposes.
>
> As previously indicated, CWIP, and the AFUDC charged thereto,

is not included in rate base until the asset is placed into service. Consequently, the deferred income tax liability provided on AFUDC should not be included in rate base as long as this AFUDC is in CWIP. This treatment is consistent with the previously cited D&Os in Docket Nos. 7766 and 04-0113."

Q. What is the main problem and concern with HECO's proposed treatment of the ADIT for "AFUDC on CWIP" and what is the remedy?

A. The ADIT for "AFUDC on CWIP" represents cost-free capital recorded on the utility's books that should be recognized in the ratemaking process. There are generally two ways to recognize such ADIT:

(1) by reducing rate base for such ADIT, or

(2) by reducing the CWIP investment base, upon which AFUDC is accrued, for such ADIT.

HECO's treatment disadvantages ratepayers by failing to reflect this ADIT by doing either (1) or (2). Consequently, HECO's ratemaking adjustment to remove the ADIT offset to rate base for "AFUDC on CWIP" should be reversed. Restoring this ADIT offset to the determination of rate base reduces rate base by $8.157 million.

Q. Has this issue come to light in the current case at least partially as a result of other changes to the treatment of ADIT that HECO is recommending for the first time in the current rate case?

A. Yes. As described in the responses to CA-IR-305, CA-IR-306 and CA-IR-466, HECO has proposed for the first time in the current rate case to <u>increase</u> rate base by adding ADIT related to tax capitalized interest (TCI) to rate base. As explained in those responses, in HECO's direct testimony in the current case, and in HECO's prior rate case in Docket No. 04-0113, as well as in the recent HELCO rate case in Docket No. 05-0315, the ADIT for TCI was excluded from rate base. HECO's response to CA-IR-466(g) indicates that "the propriety of the inclusion in rate base of the deferred income taxes related to TCI was not discovered until the Company was working on the response to CA-IR-305 in this docket." As indicated in the response to CA-IR-466(b), both the ADIT relating to the AFUDC and TCI were excluded from rate base in HECO's Docket No. 04-0113 and in HELCO Docket No. 05-0315. As indicated in the response to CA-IR-466(a), both the AFUDC and TCI ADIT balances are identified as relating to CWIP that is not presently in rate base. Moreover, as indicated in the responses to CA-IR-466(d) and (e), respectively, the CWIP investment base has not been reduced for the ADIT related to the AFUDC, and the CWIP investment base has not been increased by the ADIT related to the TCI.

As can be seen from the above, the ADIT on the "AFUDC in CWIP" and on the TCI have significant similarities and should be treated similarly for ratemaking purposes.

Q. How does your recommended ratemaking treatment for the ADIT on "AFUDC in CWIP" relate to HECO's proposed ratemaking treatment for the ADIT on TCI?

A. I find that HECO's new proposal to increase rate base for the ADIT on TCI is appropriate because such ADIT has not been reflected in the CWIP investment base upon which AFUDC is accrued. Rate base must also be reduced for the ADIT for "AFUDC on CWIP" because such ADIT has not been reflected in the CWIP investment base upon which AFUDC is accrued. My adjustment to reduce rate base for the $8.157 million ADIT for "AFUDC on CWIP" accomplishes this.

Q. Are there any other factors that you considered in reviewing this issue?

A. Yes. I also considered whether ratepayers were being provided with a reduction to current income tax expense for interest attributable to AFUDC debt. As explained in HECO's response to CA-IR-466(h), they are not.

Q. Please summarize your recommendation concerning the ratemaking treatment for ADIT for "AFUDC on CWIP."

A. The average 2007 amount of ADIT for "AFUDC on CWIP" should be reflected as a reduction to rate base for the reasons described above. As shown on DOD-110, this reduces rate base by $8.157 million.

IV. NET OPERATING INCOME ADJUSTMENTS

Q. Have you prepared an exhibit which summarizes DOD's adjustments to net operating income?

A. Yes. These adjustments are shown on DOD-111. The recommended adjustments to net operating income are discussed in the same order as they appear on DOD-111.

Q. Do you also show the impact of each adjustment on income tax expense on DOD-111?

A. Yes. The impact of each adjustment on income tax expense is shown on DOD-

111, line 21. Income taxes are generally computed using the combined state and federal income tax rate of 38.91% shown on DOD-102 and the HECO-2301 workpapers, page 12.

A. HECO's June 2007 Updates

Q. How did you reflect HECO's June 2007 updates?

A. I have reflected the results of HECO's June 2007 updates as one adjustment to net operating income, as shown on DOD-112. HECO's response to DOD-IR-95 summarized the results of HECO's updates on each line item in the statement of net operating income. The net result of HECO's updates is to reduce net operating income by $2.093 million.

Q. Should your reflection of HECO's updates to net operating income shown on DOD-112 be interpreted as an endorsement of all of HECO's updates?

A. No, it should not. Reflecting the HECO updates in the manner shown on DOD-112 was intended to adjust the starting point of my net operating income analysis to what HECO has proposed. Reflecting them in this was administratively efficient and should not be interpreted or implied as an endorsement or agreement with every aspect of what HECO adjusted in its updates.

B. Adjust Revenue for Known and Measurable Rate Changes

Q. Please explain the adjustment to revenues for known and measurable rate changes.

A. As shown on DOD-113, this adjustment increases revenue for the impact of known and measurable rate changes. Additional electric sales revenue of $57.243 million are added to incorporate the impacts of known and measurable rate changes. The impacts of this addition on other operating revenue and on operating expenses are also shown on DOD-113.

Q. Please address the primary known and measurable rate changes.

A. The primary known and measurable rate changes are as follows.

First, on September 27, 2005, the Commission issued Interim Decision and Order (D&O) No. 22050 in Docket No. 04-0113, HECO's rate case for test year 2005. In that Interim D&O, the Commission authorized the increase of HECO's then present rates by 4.36%. HECO is currently collecting that increase as a percentage of bill surcharge during the interim period before the final decision and order is issued. The Commission has not yet issued a Final D&O. If the Commission issues a Final D&O in Docket No. 04-0113 during the pendency of HECO's 2007 test year rate case, the amount of revenue at current rates would need to be adjusted to reflect the results of the Final D&O.

Second, as approved in D&O No. 23377 in Docket No. 04-0113, HECO has implemented an Interim Surcharge to collect Honolulu Low Sulfur Fuel Oil (LSFO) trucking costs and Distributed Generation (DG) fuel and trucking costs.

Finally, in HECO's June 2007 update for HECO T-3, the Company updated changes to its Energy Cost Adjustment Factor.

Q. Where did HECO present its updated estimates of revenue?

A. HECO's June 2007 Update for HECO T-3, at pages 4-6 of 41, summarized the Company's updated estimation of revenue.

Q. Please explain Exhibit DOD-113.

A. On page 1 of DOD-113, column A shows revenue at current effective rates and at present rates and the amount of additional revenue at current rates, as reflected in HECO's direct filing. Column B shows the corresponding amounts from HECO's June 2007 update. Column C shows the difference. Column D shows the DOD adjusted amounts, and Column E shows the DOD adjustment.

Column B, lines 4-10, show a breakdown of HECO's calculated $55.457 million additional electric sales revenue at currently effective rates, and the related impacts, by component. Columns D and E, lines 4-10, present similar information for the DOD's calculated amount of additional annual sales revenue at currently effective rates of $57.243 million.

As shown on DOD-113, line 19, there is a difference of $1.786 million between DOD and HECO relating to the amount of Interim Surcharge revenue produced by D&O No. 23377 in Docket No. 04-0113. As noted above, that D&O allowed HECO to implement an Interim Surcharge to collect Honolulu LSFO trucking costs and DG fuel and trucking costs.. In its June 2007 update, HECO only reflected 8/12ths of the annual revenue that ratepayers will be paying as a result of this rate increase. This was apparently based upon the surcharge commencing in May 2007. In contrast, I have reflected an annualized amount of revenue produced by this known rate change. Because this is a known and measurable change that has resulted from a rate increase approved by the Commission and is currently being charged to HECO's ratepayers, the full annual effect should be included in the determination of the revenue requirement.

Q. What would be the impact on ratepayers if the full annual amount of the rate increase represented by that Interim Surcharge is not recognized for ratemaking purposes in the current case?

A. If the full annual amount of the rate increase represented by the Interim Surcharge is not reflected for ratemaking purposes in the current case, this would result in ratepayers over-paying by the 4/12ths of the rate increase, or approximately $1.786 million, that HECO failed to recognize.

Q. How does your reflection of the adjustment to Revenue for known and measurable rate changes on DOD-113 relate to your presentation of the revenue requirement?

A. I have reflected the adjustment to Revenue for known and measurable rate changes on DOD-113 as an adjustment to net operating income. On DOD-101, I have computed the revenue deficiency based on revenue at current effective rates.

Q. How does that compare with what HECO did in its filing?

A. As shown on Exhibits HECO-2301 and HECO-2302 in its filing, HECO has presented two separate revenue requirement calculations based on (1) results of operations at current effective rates (in HECO-2301) and at present rates (in HECO-2302). On DOD-101, I summarize the results of HECO's filing and the Company's updates. The DOD's revenue deficiency shown on DOD-101, page 1, line 13, is comparable to the revenue deficiency computed by HECO for results of operations at current effective rates on HECO-2301 from the Company's June 2007 update.

Q. What is shown on page 2 of DOD-113?

A. Page 2 of DOD-113 shows selected information from HECO-2301 and HECO-2302 as adjusted in HECO's June 2007 Update that relates to identifying the impact of HECO's calculated increase in electric sales revenue of $55.457 million at currently effective rates, and the impact of that change on the other components of revenue and expense listed on DOD-113, page 1, column B, lines 4-10.

C. Remove Amortization of Pension Asset

Q. Please explain your adjustment to remove HECO's proposed amortization of a pension asset.

A. This adjustment is shown on DOD-114 and removes HECO's proposed amortization of a pension asset.

Q. What has HECO proposed for pension asset amortization, and why should it be rejected?

A. HECO has proposed to amortize into rates its estimated pension asset as of December 31, 2007 over a ten-year period. This proposal by HECO should be rejected for several reasons, including:

- HECO has not demonstrated that its pension asset as of December 31, 2007 has been funded by investors. The analysis described above in my testimony relating to excluding the pension asset from rate base shows that HECO has failed to demonstrate that its pension asset as of December 31, 2007 has been funded by investors. The analysis presented on DOD-108, page 2, shows that the pension asset was funded by ratepayers. Consequently, not only should the pension asset be excluded from rate base, no amortization of such asset should be charged to ratepayers.

- Amortization of the pension asset would charge ratepayers for a higher amount of pension expense than was determined under Statement of Financial Accounting Standards (SFAS) Nos. 87 and 158. HECO's proposed amortization is not determined under SFAS 87 or 158.
- It represents an additional amount of pension expense beyond the normal net periodic pension cost (NPPC) under SFAS 87 that has been the basis for determining the amount of pension expense for ratemaking (after appropriate adjustments for capitalization, etc.) in prior HECO rate cases.
- HECO has never included a pension asset amortization in any prior rate case. Such an adjustment is not supported by prior ratemaking practice.

The pension asset amortization is inappropriate and should be rejected for the reasons stated above.

Q. Should HECO's proposed amortization of a pension asset be rejected, even if the Commission decides to adopt some type of "pension tracking mechanism"?

A. Yes. I discuss HECO's proposal for a "pension tracking mechanism" in Section V-A of my testimony, below. However, whether some type of "pension tracking mechanism" is adopted or not, HECO's proposal for amortization of a pension asset is inappropriate, as explained above, and should be rejected.

D. *Edison Electric Institute Dues*

Q. Please explain your adjustment for Edison Electric Institute (EEI) Dues.

A. This adjustment is shown on Exhibit DOD-115 and reduces test year expense by 60,966. It reflects the removal of 49.93 percent of EEI core dues and 70 percent of the EEI Industry Structure Assessment. It does not remove any of the payment for the EEI Mutual Assistance Program.

Q. How does your proposed adjustment for EEI dues compare with HECO's proposed treatment of such dues?

A. As noted above, my recommended adjustment reflects the removal of 49.93 percent of EEI core dues. This compares with HECO's removal of 25 percent of the EEI core dues.

My recommended adjustment removes 70 percent of the EEI Industry Structure Assessment. This is the same percentage removed by HECO.

Finally, my adjustment leaves HECO's payment for the EEI Mutual Assistance Program. This component of the payment to EEI is a voluntary payment approved by the EEI Executive Committee relating to improvements for the electric utility industry's rapid response to disasters.

Q. Did HECO pay any EEI dues in 2006?

A. No. The response to DOD-IR-126 indicates that, although HECO was a member of EEI in 2006, EEI waived its 2006 membership fees for HECO. Therefore, HECO did not pay any 2006 EEI dues.

Q. How did you derive your recommended disallowance percentage for EEI core dues?

A. DOD-IR-127(e) requested HECO to provide a breakout of EEI dues for each year 2005, 2006 and 2007 into the following NARUC-specified operating expense categories: (1) legislative advocacy, (2) legislative policy research, (3) regulatory advocacy, (4) regulatory policy research, (5) advertising, (6) marketing, (7) utility operations and engineering, (8) finance, legal, planning and customer service, and (9) public relations. In response, HECO did not provide any of this requested information. Consequently, I have relied upon information from another recent rate case for a breakout of the EEI core dues into the NARUC-specified categories for 2005. A summary of the EEI core dues by NARUC-specified category is shown on DOD115, page 2. EEI Core Dues relating to the following activities should be excluded from rates:

- o Legislative Advocacy
- o Regulatory Advocacy
- o Advertising
- o Marketing
- o Public Relations

The sum of EEI Core Dues activities for these NARUC categories totals 49.93 percent, as shown on DOD-115, page 2.

Q. What is the purpose of the NARUC-designated categorization of EEI expenditures?

A. The purpose of the NARUC-designated categorization of EEI expenditures is to assist regulatory commissions to decide which, if any, of the costs of the association should be approved for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities. Certain expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit. The NARUC-designated categories of EEI expenditures are thus intended to be helpful to state utility regulatory commissions.

Q. Was this same percentage for the EEI core dues disallowance recently used in any other electric utility rate cases?

A. Yes. The Arkansas Public Service Commission in Docket No. 06-101-U, an Entergy Arkansas, Inc., rate case, in Order No. 10 (6/15/07) adopted a similar adjustment to reflect the disallowance of 49.93 percent of EEI core dues. This 49.93 percent disallowance of EEI core dues corresponds to the above-identified activity categories.

E. Security Services Expense

Q. Please explain your adjustment for Security Services Expense.

A. This adjustment is shown on Exhibit DOD-116 and reduces expense by approximately $117,000. As explained in response to several CA and DOD information requests, including DOD-IR-105, CA-IR-339, CA-IR-486 and others, HECO's security services contractor has been experiencing a staffing shortfall due to difficulties in hiring and retaining employees. Because of the staffing shortfall, HECO's security contractor has not been able to provide the security officers and hours stipulated in the contract, or budgeted for 2007 by HECO. As shown on DOD-116, HECO has recorded security services expense related to 2007 work of $266,604 through June 2007. HECO estimates outstanding invoices for 2007 security services work for the remainder of June 2007 to be $40,072. The total for security services work through June 2007 is $306,676. The June 2007 expense annualized is $613,352. HECO's proposed expense of $730,280 should be reduced by $116,928.

F. *"Community Process" Expense*

Q. Please explain the adjustment for "Community Process" Expense.

A. This adjustment removes 50% of the $660,000 of outside services-general expense for supporting the "Community Process" that was identified in the responses to CA-IR-288, CA-IR-372, and other responses. The purpose of this adjustment is to reflect that HECO's "Community Process" has elements of corporate image building and donations, but has been distinguished by HECO from other donations, which would be recorded in a below-the-line account. Because the "Community Process" as described by HECO may provide benefits to both shareholders and ratepayers, I have allocated the expense on a 50/50 basis between shareholders and ratepayers.

Q. What is HECO's "Community Process"?

A. As stated in the response to CA-IR-373, "Community Process" is difficult to describe by project. In that response, HECO has identified four areas involving "Community Process" in which the Company is actively involved, as follows:

> "First, "Community Process" includes a willingness to be guided by the community not only in the final product but also in the means to achieve that product. The Company recognizes its constituencies are diverse and as a result the process requires active listening on the part of the Company through engagement with neighborhood communities as well as organizations and business partners that are attuned to cross sections of the Oahu community. The Company as the sole electric utility for the entire island, supports organizations, activities, and events which benefit the Oahu community in general. Being one of the largest corporate entities and employers on the island of Oahu, we have been asked to assist and support various organizations which reach out to the residents and communities on Oahu. These actions demonstrate responsible corporate leadership and citizenship which are vital to building and sustaining healthy communities.
>
> Second, Hawaiian Electric also works with the film programs of the high schools in the impacted areas (West Oahu/Waianae Coast) to find appropriate projects for them to help educate either specific public audiences or the general public on energy related issues. The Company has actively worked with and supported the West Oahu/Waianae Coast high schools to engage the students in reaching out to the community and their peers to learn more about energy, renewable energy, and energy conservation. The students from these high schools have created through their own work, creativity and ideas, video presentations on key energy issues. Their presentations have been shown as public service announcements, at Hawaiian Electric's Live Energy Lite community fair (held yearly in the fall), and at Sunset on the Beach festivities on the Leeward Coast. The Company has also supported events which encourage youth involvement and promote the exchange of ideas through various media vehicles.
>
> Third, the Company creates its own targeted message paths through special meetings, regional newspapers, "infomercials/advertorials" as part of its effort to engage the various segments of the community in the importance of the role everyone plays in conserving energy, understanding sustainability and dealing with energy issues for Hawaii.
>
> Fourth, the Company supports the funding for special needs in the impacted areas (West Oahu/Waianae Coast), which is critical in order to maintain the relationships and ongoing communications and dialogue with residents in the impacted areas."

Q. How does HECO distinguish "Community Process" expenditures from donations?

A. Per the response to DOD-IR-129(b), expenditures to support the "Community Process" are limited to the four areas described above, **"and to groups and organizations that support education, environment, culture, health, social welfare and the military.** Contributions recorded in Account 426 are not limited to those areas of interest." (Emphasis supplied.) Thus, the "Community Process" expenditures, at least in part, are similar to donations.

Q. What benefits has HECO cited for its "Community Process" expenditures?

A. The responses to CA-IR-373 and DOD-IR-128 cite benefits of engaging the community in learning about energy and energy conservation, and providing targeted messages on energy issues, including working with the Native Hawaiian community with respect to the development of wind and other renewable energy resources.

HECO's response to DOD-IR-129 claims that its "efforts to support this community process are an extraordinarily sound investment in minimizing dispute and litigation and the resulting costs that can add to a project, and allowing necessary system reliability improvements to occur in a timely manner." The "Community Process" expenditures are thus intended to prevent challenges to infrastructure projects and to facilitate timely implementation.

Q. Has HECO demonstrated that its "Community Process" expenditures are cost effective?

A. Not really. One of the areas involved in the "Community Process" was the Company's efforts to establish a wind farm on the upper area of the Kahe Power Plant.

Q. What is the status of the Company's efforts to establish a wind farm on the upper area of the Kahe Power Plant?

A. My understanding is that it is no longer under consideration. HECO abandoned the Kahe wind farm project after encountering local opposition to building it on that site.

Q. If HECO's "Community Process" expenditures were effective in minimizing opposition to construction projects, would that benefit shareholders as well as ratepayers?

A. Yes, it would. In general, shareholders bear the risk and benefit of cost fluctuations between rate cases. If the "Community Process" improves HECO's corporate image and minimizes opposition to proposed new infrastructure, this would benefit shareholders.

G. *Income Taxes – Interest Synchronization*

Q. Please explain the adjustment for interest synchronization.

A. As shown on DOD-118, the interest synchronization adjustment synchronizes the rate base and cost of capital with the tax calculation. It is calculated by applying the DOD's recommended weighted cost of debt to the adjusted rate base for HECO to obtain a synchronized interest deduction for use in the calculation of test year income tax expense. As shown on DOD-118, I applied DOD witness Hill's recommended weighted cost of debt, which is 2.79% and can be found on DOD-105, line 14, to the adjusted rate base amount in order to determine the pro forma interest deduction to be used in calculating income tax expense for the 2007 test year. The combined state and federal income tax rates are applied to the resulting interest deduction difference to determine the amount of adjustment to income tax expense for interest synchronization.

Q. Did HECO reflect an interest synchronization adjustment in its filing?

A. No. HECO did not reflect a synchronized interest calculation in its filing. Thus, the interest expense used by HECO has not been properly coordinated with its rate base or cost of capital.

Q. Why did HECO not apply interest synchronization?

A. The response to DOD-IR-104(e) states HECO's reasons for disagreeing with the interest synchronization procedure. HECO's primary reasons appear to be that the Commission did not apply interest synchronization in prior cases, and that "interest synchronization imputes hypothetical interest on rate base funded by federal investment tax credits, which is interest-free."

Q. Is that a valid reason for not using interest synchronization?

A. No. The objections that have historically been raised by utilities regarding the application of synchronized interest to rate base funded by federal investment tax credits have been thoroughly refuted. The controversy over interest synchronization on rate base funded by federal investment tax credits existed for several years, but is no longer a legitimate issue. Several FERC rate decisions in which interest was synchronized were appealed to the Courts by the respective utilities on the grounds that such orders placed the companies' Investment Credits in jeopardy. In each instance, the Appeals Court upheld the FERC decision. Nevertheless, the controversy continued.

In 1985, the IRS finally agreed to clarify its position on the matter of interest synchronization. After extensive consideration, it issued Treasury Decision 8089 in May, 1986. That document contained final regulations clearly indicating that interest synchronization was <u>not</u> a violation of the Internal Revenue Code for utilities that selected Option 2 for ratemaking. The IRS concluded that synchronization of interest does <u>not</u> result in a reduction of cost of service that is attributable to the Credit. That conclusion was based on the presumption similar to the reasoning underlying the aforementioned decisions of the appeals Court, that:

> "In the absence of the credit the additional capital needed to finance investment property generally would be obtained from a similar proportion of debt and equity as in the existing capital structure of the utility. Synchronization of interest properly takes into account the additional interest expense that would have been incurred in those circumstances."

Q. Are you aware of any theories that could be asserted by a utility as a reason for failing to make an interest synchronization adjustment?

A. Not valid ones. As noted above, many years ago, before the interest synchronization adjustment began to gain overwhelming regulatory support and recognition, sometimes utilities would assert that it could result in a "normalization violation" under the Internal Revenue Code and thus jeopardize the use of accelerated tax depreciation or investment tax credits. However, as described above, it has subsequently become well settled and widely acknowledged that such arguments have no current validity. Consequently, the interest synchronization adjustment is routinely made in utility rate cases, and the basic calculation method or its validity and appropriateness is typically no longer even a topic of debate.

Q. Is the interest synchronization adjustment routinely accepted by utilities and utility regulators as an appropriate and necessary adjustment for ratemaking purposes in the utility rate cases in which you have been involved, especially in recent years?

A. Yes. Utilities and utility regulators routinely accept the interest synchronization adjustment as appropriate and necessary for ratemaking purposes in the utility rate cases in which I and other Larkin & Associates' expert witnesses and rate analysts have been involved. Typically, the interest synchronization adjustment is presented in the utility's initial filing and then is only adjusted, if necessary, for changes to rate base or cost of capital.

Q. If the widely accepted interest synchronization procedure were <u>not</u> to be employed in this case, would an alternative adjustment to the interest deduction in the income tax calculation be necessary?

A. Yes. The interest deduction in the income tax calculation would need to be adjusted for the amount of interest on short term debt. DOD-119, shows the alternative calculation, related to the different amounts for short term debt proposed by HECO and DOD, that would be needed if the interest synchronization were not used.

As shown on DOD-119, HECO has proposed short term debt of $38.971 million. In comparison, DOD witness Hill has proposed short term debt of approximately $70.052 million, based on the most recent five quarters of actual information. Both HECO and DOD have applied an interest rate of 5.00% to short term debt. The difference in short term debt interest results in a reduction to income tax expense of approximately $605,000.

Q. Please explain why it would be preferable to use the widespread regulatory practice of interest synchronization in this proceeding.

A. Rather than making a separate, alternative adjustment for income taxes relating only to the higher amount of short term debt that DOD witness Hill has recommended, the widespread regulatory practice of interest synchronization in this proceeding would be vastly preferable. The cost of debt and the cost of equity are well examined during the cost of capital phase of a rate proceeding. The amount of interest expense collected in rates is included in the return on rate base, and only by extremely rare coincidence would that equal the utility's actual recorded interest expense.

Prior to the widespread adoption of "Interest Synchronization", state utility regulatory commissions experienced the parties re-litigating the interest expense issue for the income tax calculation. Many different elements could be included or excluded in making an interest expense calculation for determining taxable income; such as AFUDC interest, cash interest paid, interest expense used for the actual income tax return. However, these arguments are made moot by using the same interest expense used in the cost of capital and included in rates for calculating income tax expense. This is accomplished by using the authorized weighted cost of debt, multiplied times the authorized rate base, to determine interest expense for calculating taxable income for determining the utility's pro forma income tax expense. This well-established procedure is called "Interest Synchronization" because it appropriately "synchronizes" the elements of the ratemaking formula (cost of capital, rate base, and net operating income) that affect income tax expense. Thus, the resulting rates are appropriately consistent and the need to re-litigate interest expense issue is avoided. when interest synchronization is adopted. Interest Synchronization is theoretically sound because it will harmonize the interest deduction for calculating taxable income with the interest expense included in cost of capital and simplify the ratemaking process.

Q. Have you included with your testimony some additional documentation in support of why the Commission should adopt the interest synchronization method in the current HECO rate case?

A. Yes. HECO provided an illustrative discussion of interest synchronization in a commission findings and order in response to DOD-RIR-36 in Docket No. 04-0113, pages 155 and 156 of 446. I have attached those two pages are as DOD-120 for convenience.

Further discussion of the development and history of interest synchronization as a ratemaking method is provided at pages 13, 14, and 15 of the 42nd annual training manual for the "Regulatory Studies Program" presented by the Institute of Public Utilities at Michigan State University. I have attached those pages for convenience as DOD-121, pages 1-3. Similarly, the 46th annual training manual for the "Regulatory Studies Program" presented by the Institute of Public Utilities at Michigan State University, the discussion of Interest Synchronization was limited to three power point slides illustrating the calculation and impact on allowable income tax expense. I have attached these pages as DOD-121, pages 4-6, for convenience.

Q. Why should the Commission apply the interest synchronization method that has been so widely adopted by other state regulatory commissions and the utilities they regulate in the current HECO rate case, when the Commission has not adopted the interest synchronization method in prior rate cases?

A In the instant case, HECO used this Commission's traditional method of calculating the interest deduction for taxable income instead of the interest synchronization method. In some circumstances, the traditional method may produce results that are similar to interest synchronization. However, the underlying reasons that may have been raised by utilities such as HECO decades ago for <u>not</u> using interest synchronization – such as HECO's arguments that interest should not be applied to the rate base that was funded with federal investment tax credits – have been thoroughly refuted, as explained above, and are no longer valid issues.

As to overruling PUC precedent on interest expense in the income tax calculation for ratemaking purposes, the Hawaii Supreme Court wrote generally: :

"We do not lightly disregard precedent; we subscribe to the view that great consideration should always be accorded precedent, especially one of long standing and general acceptance. Yet, it does not necessarily follow that a rule established by precedent is infallible. If unintended injury would result by following the previous decision, corrective action is in order; for we cannot be unmindful of the lessons furnished by our own consciousness, as well as by judicial history, or the liability to error and the advantages of review. As this court has long recognized, we not only have the right but are entrusted with a duty to examine the former decisions of this court and, when reconciliation is impossible, to discard our former errors."[1]

In summary, it is generally better to establish a new rule than to follow a bad precedent

The interest synchronization method is widely used by other utilities and utility regulatory commissions because it appropriate coordinates the elements of the ratemaking formula and is fair to all parties. The DOD urges the Commission to adopt interest synchronization in the current HECO rate case and as official policy moving forward because it is a superior method that results in appropriately coordination of the elements of the ratemaking formula (rate base, rate of return, and operating expenses) and because it balances the concerns of all stakeholders in an impartial and equitable way.

1 Kahale v. City and County of Honolulu, 104 Hawai'i 341, 347, 90 P.3d 233, 239, at footnote 7. Francis v. Lee Enters., Inc., 89 Hawai'i 234, 236, 971 P.2d 707, 709 (1999) (internal citations, quotations, and bracket omitted); see also State v. Jenkins, 93 Hawai'i 87, 111-12, 997 P.2d 13, 37-38 (2000) (citing Francis, supra); Parke v. Parke, 25 Haw. 397, 401 (1920) "It is generally better to establish a new rule than to follow a bad precedent".

H. Research, Development and Demonstration Expenses in Miscellaneous O&M

Q. Please explain your adjustment for Research, Development and Demonstration (RD&D)[2] Expenses in Miscellaneous O&M.

A. This adjustment reduces HECO's estimated 2007 RD&D expenses in Miscellaneous O&M by $375,000 to normalize such expenses. HECO's proposed amount for the 2007 test year of approximately $1.156 million is substantially higher than the amount incurred in 2005 or 2006, as summarized in the following table:

Non-EPRI RD&D in Miscellaneous O&M
(Thousands of Dollars)

Year	Source	Non-EPRI RD&D	HECO Proposed Exceeds Amount By $	HECO Proposed Exceeds Amount By %
2005	CA-IR-452, page 2	$ 865	$ 291	33.6%
2006	CA-IR-452, page 2	$ 323	$ 833	257.9%
2007	CA-IR-452, page 2 & T-13 Update	$ 1,156		
	Average	$ 781	$ 375	48.0%

Q. What other RD&D spending does HECO project for the 2007 test year?

A. HECO also projects an expense for the Electric Power Research Institute (EPRI) of $2.203 million, of which 77.094% is allocated to HECO, for a projected 2007 test year expense amount of $1.608 million. This is shown on HECO's June 2007 update for T-13, page 8 of 24.

Q. Was EPRI expense included in HECO's allowed expenses in Docket No. 04-0113?

A. Yes. As listed in the response to CA-IR-452, page 2, the 2005 test year

2 HECO refers to this as "R&D" in its responses.

included approximately $2.49 million of R&D, including a substantial amount for EPRI. HECO's actual 2005 expense for EPRI dues listed in that response is $1.529 million.

Q. After getting the EPRI dues of approximately $1.5 million included in rates in the 2005 test year, did HECO actually spend the money on EPRI dues in 2006?

A. No. As listed in the response to CA-IR-452, page 2, HECO's total R&D expense in Miscellaneous O&M for 2006 was only $323,000, and there was no expense incurred by HECO in 2006 for EPRI dues.

Q. What does this illustrate?

A. This illustrates that the RD&D expenses are discretionary, and that HECO will not necessarily spend the amount that it requests be included in rates. Consequently, HECO should not be granted more than a "normalized" amount of RD&D expenses in the test year.

Q. What amount of RD&D in Miscellaneous O&M do you recommend, and how does that compare with HECO's request?

A. The following table summarizes my recommendation for Including the EPRI and non-EPRI RD&D expense in Miscellaneous O&M of $2.389 million, and how this compares with HECO's request:

EPRI and Non-EPRI RD&D in Miscellaneous O&M
(Thousands of Dollars)

	HECO	DOD	Difference
EPRI	$ 1,608	$ 1,608	$ -
Non-EPRI	$ 1,156	$ 781	$ (375)
Total	$ 2,764	$ 2,389	$ (375)

I. Average Test Year Employees

Q. In Docket No. 04-0113 you had recommended an adjustment relating to "open positions" that HECO had included in its requested test year O&M, but which were not filled. Does a similar adjustment appear to be necessary in the current 2007 test year case?

A. Yes. An adjustment relating to "open positions" that HECO had included in its requested test year O&M, but which were not filled appears to be necessary in the current 2007 test year case to adjust for the gradual impact of filling the significant level of "open positions" in HECO's 2007 test year filing. In essence, an adjustment is needed to reflect that:

- HECO had not filled the "open positions" as of January 1, 2007, the beginning of the test year;
- HECO might fill the remaining open positions by December 31, 2007, the end of the test year; and
- A 2007 "average" test year is being used for purposes of determining HECO's revenue requirement in this proceeding.

Using an average of the "open positions" that HECO had not filled at the beginning of the test year, but might fill by the end of the test year, would also be consistent with the use of an "average" test year. Additionally, it would give HECO the benefit of the doubt as to whether all of the "open positions" are really needed or will be filled.

Q. How many "open positions" did HECO assume in its 2007 test year filing?

A. HECO's response to CA-IR-465 indicates that HECO's filing assumed "an updated 2007 end-of-test-year" work force of 1,560 positions. That response, on page 5 of 5 indicates an actual employee count of 1,471 as of June 30, 2007, consisting of 1,465 full-time, 1 part-time, and 5 temporary employees. As of June 30, 2007, there are 89_ "open" positions. As shown on DOD-IR-122, page 3 of 7, for January through June 2007, HECO had the following levels of recorded employee count in each month:

Recorded Employee Count
Versus HECO's Assumed Level

Month	Recorded Employee Count	HECO Updated EOY Test Year	Difference
	(A)	(B)	(C)
Jan	1,449	1,560	111
Feb	1,450	1,560	110
Mar	1,452	1,560	108
Apr	1,461	1,560	99
May	1,465	1,560	95
June	1,471	1,560	89

Source:
Col.A: DOD-IR-122
Col.B: DOD-IR-12 and CA-IR-465

Q. How did HECO's filing treat "open" positions for the 2007 test year?

A. For the most part, HECO's filing treated "open" positions for the 2007 test year as if they were filled throughout the 2007 test year.

Q. Has HECO provided an estimate of the wages and benefits of "open" positions included in its 2007 test year forecast?

A. Not in a format that I was able to utilize in order to quantify an adjustment. An adjustment is clearly needed to remove the excess expense related to the "open positions." One way of achieving this would be to reflect the estimated wages and benefits of "open" positions included in HECO's 2007 test year forecast as if they were filled ratably throughout the 2007 test year.

Q. Is it certain that HECO will fill the remaining "open" positions by the end of the test year?

A. No. Thus, while HECO has made some progress in filling "open" positions during 2007, there is no assurance that all of the "open" positions would be filed by December 31, 2007. Clearly, many of the "open" positions upon which HECO has based its estimated test year labor cost projections were <u>not</u> filled at the start of the 2007 test year, and have not yet been filled as recently as June 30, 2007. Page 7 of HECO's response to DOD-IR-122 shows 94 "open" positions that have not yet been filled as of May 31, 2007. Similarly, HECO's response to CA-IR-465 shows 89 "open" positions as of June 30, 2007.

Q. Is an assumption for vacancies resulting from additional turnover incorporated in HECO's forecast?

A. No, it does not appear that a "vacancy" factor was included in HECO's 2007 labor cost projections. Rather, HECO's approach was generally to assume for ratemaking purposes that each "open" position was filled throughout the 2007 test year. However, as would be the case with any large company, one would expect additional vacancies to occur and some time lag between vacancies occurring and the subsequent filling of vacant positions.

Q. Is HECO's proposed ratemaking treatment for 2007 "open" positions consistent with the use of an average test year?

A. No, it is not. The "open" positions were not filled at the beginning of the test year and might, or might not, be filled by the end of the test year. Assuming that the positions were filled throughout the test year, as HECO has done, is not consistent with the use of an average test year. HECO is experiencing sales and revenue growth; however, consistent with the use of an average test year, HECO's revenues have not been updated to December 31, 2007 levels. HECO should not be allowed to select specific costs, such as labor, that are known to be increasing and annualize them at year-end levels, while failing to move the other ratemaking elements, including revenue, to a matched, year-end point in time. HECO has annualized labor expense to year-end in a test year revenue requirement that is otherwise quantified using an average test year approach. HECO's proposed labor cost for "open" positions must be adjusted in order to be consistent with the use of an average test year for rate base, electric sales revenues and other operating expenses.

V. OTHER ISSUES

Q. Are there any other issues not directly relating to the determination of HECO's revenue requirement that you wish to address?

A. Yes. I would like to address HECO's proposals for a pension tracking mechanism and an OPEB tracking mechanism.

A. HECO's Proposed Pension Tracking Mechanism

Q. What did HECO state in its direct testimony about whether it was proposing any new adjustment clauses in this case?

A. The following Q&A appears at page 14 of HECO T-23:

Q. Has the Company proposed any new adjustment clauses, for pension costs for example, in this proceeding?

A. The Company is not ready to do that. It needs to extensively examine how these mechanisms would be specifically applied and what their implications would be. Although the Company has not proposed any new adjustment clauses in this proceeding, it may do so in a future proceeding.

Q. Has HECO proposed a "pension tracking mechanism"?

A. Yes. The Company's June 2007 update to HECO T-10, in Attachments 7 and 8, presents a background for, and the Company's proposed "pension tracking mechanism," respectively.

Q. Does the DOD support HECO's proposal for a "pension tracking mechanism"?

A. No, to the contrary. DOD opposes HECO's requested "pension tracking mechanism" for the following reasons:

- HECO's proposal includes provisions that are totally unacceptable, such as the proposal (discussed above) to amortize HECO's estimated December 31, 2007 pension asset into rates over ten years.
- As a general rule, expense tracking mechanisms constitute "single issue ratemaking" and should only be adopted where there are sufficiently compelling circumstances, which HECO has failed to demonstrate.
- Approving a "pension tracking mechanism" would shift the risk (and benefit) of fluctuations in pension expense away from shareholders and onto ratepayers.
- Approving such a "pension tracking mechanism," by essentially guaranteeing the rate recovery of pension expense, could remove or reduce the incentive on management to modify the postretirement benefit

plan to reduce cost.

Q. HECO refers to a "pension tracking mechanism" that was adopted in Docket No. 05-0315, in a HELCO rate case. Does that appear to you to represent a controlling precedent that must result in imposing a "pension tracking mechanism" on HECO's ratepayers in the current rate case?

A. No. For the following reasons, the HELCO settlement, which apparently included a "pension tracking mechanism" does not appear to represent a controlling precedent that must, or should, result in imposing a "pension tracking mechanism" on ratepayers in HECO's current rate case.

First, DOD was not a participant in the HELCO rate case.

Second, the "pension tracking mechanism" adopted for HELCO was the result of a settlement between the CA and HELCO. While that HELCO settlement was approved by the Commission, there is no indication that such approval was intended to result in forcing an unacceptable "pension tracking mechanism" on HECO's ratepayers, including ratepayers such as the DOD, which did not participate in the HELCO case.

Third, HECO has not demonstrated that the facts and circumstances related to its situation and HELCO's are identical or substantially similar. My understanding is that HECO's pension costs are much larger than HELCO's.

Consequently, "pension tracking mechanism" for HECO should be evaluated on its own merits, or lack thereof, and the decision should not be influenced by the settlement between the CA and HELCO in Docket No. 05-0315.

Q. If a "pension tracking mechanism" were to be adopted for HECO, are there some features in HECO's proposal that are simply unacceptable?

A. Yes. As noted above, DOD recommends against adopting a "pension tracking mechanism" for HECO. However, if any "pension tracking mechanism" were to be adopted for HECO in the current case, (1) it should be adopted for prospective application only, and (2) **there should be no provision for recovery of any past balances that accrued prior to the date of adoption, i.e., no amortization of HECO's estimated December 31, 2007 pension asset, or any other pension asset that was recorded by HECO prior to the adoption of the "pension tracking mechanism."**

Preferably, HECO's proposed "pension tracking mechanism" should be rejected, and pension expense should be treated generally in the same manner as other expenses which do not have special ratemaking treatment.

B. HECO's Proposed OPEB Tracking Mechanism

Q. Has HECO proposed a Tracking Mechanism for Postretirement Benefits Other Than Pensions (OPEB)?

A. Yes. HECO's June 2007 update for HECO T-10, Attachment 7, page 4, generally describes the OPEB Tracking Mechanism proposed by HECO, and Attachment 9 to that update contains HECO's proposed OPEB Tracking Mechanism.

Q. Should HECO's proposed OPEB Tracking Mechanism be adopted?

A. No. For reasons similar to my earlier discussion concerning HECO's proposed pension tracking mechanism, HECO's proposed OPEB Tracking Mechanism should be rejected:

- As a general rule, expense tracking mechanisms constitute "single issue ratemaking" and should only be adopted where there are sufficiently compelling circumstances, which HECO has failed to demonstrate.
- Approving an "OPEB tracking mechanism" would shift the risk (and benefit) of fluctuations in OPEB expense away from shareholders and onto ratepayers.
- Approving such a "OPEB tracking mechanism," by essentially guaranteeing the rate recovery of OPEB expense, could remove or reduce the incentive on management to modify the postretirement benefit plan to reduce cost.

Q. Does this conclude your direct testimony?

A. Yes, it does.

QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Wisconsin, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)

U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)

R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)

Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-02REO1	Connecticut Light & Power Company (CT DPUC)
Docket No. 03-07-01RE	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. 01-05-19 REO3	Yankee Gas Service (CT DPUC)
Docket No. G-01551A-00-0309	Southwest Gas Corporation (Arizona Corporation Commission)
Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. 05-116-U	Entergy Arkansas, Inc. (Arkansas PSC)
Case No. 04-137-U	Southwest Power Pool RTO (Arkansas PSC)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Case No. U-14347	Consumers Energy Company (Michigan PUC)
E-01345A-06-009	Arizona Public Service Company (Arizona CC)
05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power Co. (West Virginia PSC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)

Exhibits

Accompanying the Direct Testimony of Ralph C. Smith

Number	Description	Pages
	Revenue Requirement Summary Schedules	
DOD-101	Calculation of Revenue Deficiency	2
DOD-102	Gross Revenue Conversion Factor	1
DOD-103	Adjusted Rate Base	1
DOD-104	Adjusted Net Operating Income	1
DOD-105	Capital Structure and Cost Rates	1
	Rate Base Adjustments	
DOD-106	Summary of Adjustments to Rate Base	1
DOD-107	HECO June 2007 update	1
DOD-108	Remove Net Pension Asset	2
DOD-109	Cash Working Capital	2
DOD-110	Accumulated Deferred Income Taxes	1
	Net Operating Income Adjustments	
DOD-111	Summary of Adjustments to Net Operating Income	1
DOD-112	HECO June and July 2007 Updates	1
DOD-113	Revenues, Known Rate Changes	2
DOD-114	Remove Amortization of Pension Asset	1
DOD-115	Edison Electric Institute Expense	2
DOD-116	Security Services Expense	1
DOD-117	"Community Process" Expenses	1
DOD-118	Income Taxes - Interest Synchronization	1
DOD-119	Income Taxes - Alternative Adjustment for Short Term Debt Interest	1
DOD-120	Interest Synchronization DOD-RIR-36 in Docket No. 04-0113, pages 155 and 156 of 446	2
DOD-121	Development and history of interest synchronization as a ratemaking method is provided at pages 13, 14, and 15 of the 42nd annual training manual for the "Regulatory Studies Program" presented by the Institute of Public Utilities at Michigan State University and 3 presentation slides	6
DOD-122	Research, Development and Demonstration Expense in Miscellaneous O&M	1
	Total Pages	33
	Total Pages Including Contents Page	34

Hawaiian Electric Company, Inc.
Calculation of Revenue Deficiency
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	Reference	Per HECO (A)	Per DOD (B)	Difference (C)
1	Adjusted rate base at proposed rates	DOD-103	$1,214,312	$ 1,150,720	$ (63,592)
2	Rate of return	DOD-105	8.92%	7.70%	
3	Net operating income required		$ 108,317	$ 88,605	$ (19,712)
4	Adjusted net operating income	DOD-104	$ 24,058	$ 58,038	$ 33,980
5	Net operating income deficiency		$ 84,259	$ 30,567	$ (53,692)
6	Gross revenue conversion factor	DOD-102	1.797947	1.797979	
7	Calculated revenue deficiency		$ 151,493	$ 54,959	$ (96,534)
8	Difference, Lines 7 & 9		$ 12		
9	Proposed revenue deficiency, as filed	HECO-2302	$ 151,505		
10	Impact of HECO's Updates, increases rev req		$ 1,319		
11	Revenue deficiency	Note a	$ 152,824		
12	Difference, lines 11&13		$ 55,504		
13	Revenue deficiency at current rates	Note b	$ 97,320	$ 54,959	$ (42,361)

Notes and Source

Col.A: HECO-2301

	Revenue Deficiency Components	DOD-102 Portion	Amount ($000)	Revenue Taxes
7.1	PSC Tax and PUC Fees Rates	6.3790%	$3,506	Lines 7.1 and &.2
7.2	Franchise Tax	2.4780%	$1,362	$4,868
7.3	Uncollectibles	0.1000%	$55	
7.4	Income taxes at composite rate	35.4250%	$19,469	
7.5	Net Operating Income	55.6180%	$30,567	
7.6	Totals	100.0000%	$54,959	

(a) HECO June 2007 update for T-23 (submitted 7/24/07), HECO-2302 updated
(b) HECO June 2007 update for T-23 (submitted 7/24/07), HECO-2301 updated

Hawaiian Electric Company, Inc.
HECO June and July 2007 Updates
(Thousands of Dollars)
Test Year Ending December 31, 2007

DOD-101
Docket No. 2006-0386

Line No.	Description	Reference	Adjustment Amount (A)	Multiplier (B)	Revenue Requirement Amount (C)
1	Revenue Requirement-per HECO Filing	DOD-101		Pre-Tax Return Difference DOD-105	$ 151,505
2	Rate of Return Difference on HECO rate base Before Pro Forma Working Cash	DOD-103	$ 1,216,188	-2.20%	$ (26,756)
3	Subtotal Revenue Requirement				$ 124,749
	Rate Base Adjustments	Sub-Reference:	Reference: DOD-106	Pre-Tax Return DOD-105	
4	HECO June 2007 update	DOD-107	$ (13,100)	13.84%	$ (1,813)
5	Remove Net Pension Asset	DOD-108	$ (36,291)	13.84%	$ (5,023)
6	Cash Working Capital	DOD-109	$ (7,000)	13.84%	$ (969)
7	Accumulated Deferred Income Taxes	DOD-110	$ (8,157)	13.84%	$ (1,129)
8	Subtotal Rate Base Adjustments Before Pro Forma Working Cash		$ (64,548)		$ (8,934)
9	Change in Working Cash at Proposed Rates	DOD-112	$ 956	16.04%	$ 153
10	Adjusted Rate Base		$ 1,152,596		$ (8,781)
11	Adjusted Net Operating Income - per HECO	DOD-101 DOD-104	$ 24,058		
	Net Operating Income Adjustments	Sub-Reference:	Reference: DOD-111	GRCF DOD-102	
12	HECO June and July 2007 Updates	DOD-112	$ (2,093)	1.797979	$ 3,763
13	Revenues, Known Rate Changes	DOD-113	$ 31,859	1.797979	$ (57,282)
14	Remove Amortization of Pension Asset	DOD-114	$ 3,088	1.797979	$ (5,552)
15	Edison Electric Institute Expense	DOD-115	$ 37	1.797979	$ (67)
16	Security Services Expense	DOD-116	$ 71	1.797979	$ (128)
17	"Community Process" Expenses	DOD-117	$ 202	1.797979	$ (363)
18	Income Taxes - Interest Synchronization	DOD-118	$ 587	1.797979	$ (1,055)
19	Research, Development and Demonstration Exp.	DOD-122	$ 229	1.797979	$ (411)
20	Net Operating Income Adjustments		$ 33,980		$ (61,095)
21	Adjusted Net Operating Income		$ 58,038		
22	Reconciled Revenue Requirement				$ 54,873
23	Unreconciled Difference				$ 86
24	Recommended Revenue Requirement	DOD-101, page 1			$ 54,959

Hawaiian Electric Company, Inc.
Gross Revenue Conversion Factor
Test Year Ending December 31, 2007

Exhibit DOD-102
Docket No. 2006-0386
Page 1 of 1

Line No.	Description	Amount	Reference
1	Operating revenue increase	1.00000	
	Less: Revenue Taxes and Uncollectibles:		
2	PSC Tax and PUC Fees Rates	0.06379	HECO-2301 workpapers support
3	Franchise Tax	0.02478	HECO-2301 workpapers support
4	Uncollectibles	0.00100	HECO-2301 workpapers support
5	Subtotal Revenue Taxes and Uncollectibles	0.08957	HECO-2301 workpapers support
6	Taxable income for ratemaking	0.91043	Line 1 - Line 5
7	Income taxes at composite rate	0.35425	38.91% x Line 6 HECO-2301 workpapers support
8	Net Operating Income	0.55618	Line 6 - Line 7
9	Gross revenue conversion factor	1.797979	Line 1 / Line 8
	Reciprocal of income tax rate		
10	(1 - .38910 composite income tax rate)	0.6109	0.3891
	Check		
11	Subtotal Revenue Taxes and Uncollectibles	0.08957	Line 5
12	Income taxes at composite rate	0.35425	Line 7
13	Sum	0.44382	Note A
14	Net Operating Income	0.55618	Line 1 - Line 13
15	Gross revenue conversion factor	1.797979	Line 1 / Line 14

Notes

[A]	HECO-2301 workpapers support shows 0.44381		
[B]	HECO proposed Operating Income Divisor	0.55619	HECO-2301 workpapers support
	Equivalent gross revenue conversion factor	1.797947	Line 1 / [B]

Hawaiian Electric Company, Inc.
Adjusted Rate Base
Test Year Ending December 31, 2007

DOD-103
Docket No. 2006-0386

Line No.	Description	HECO As Filed (A)	DOD Adjustments (B)	DOD Adjusted (C)
	INVESTMENT IN ASSETS SERVING CUSTOMERS			
1	Net Plant In Service	$ 1,367,090	$ (16,084)	$ 1,351,006
2	Property Held for Future Use	$ 3,380	$ (1,338)	$ 2,042
3	Fuel Inventory	$ 52,706	$ 378	$ 53,084
4	Materials & Supplies	$ 12,838	$ -	$ 12,838
5	Unamortized Net SFAS 109 Regulatory Asset	$ 54,628	$ (4,211)	$ 50,417
6	Prepaid Pension Asset	$ 161,188	$ (161,188)	$ -
7	Unamortized OPEB Regulatory Asset	$ 7,160	$ (7,160)	$ -
8	OPEB Regulatory Asset	$ 30,275	$ (30,275)	$ -
9	Unamortized System Development Costs	$ 3,009	$ (688)	$ 2,321
10	Unamortized DSG Regulatory Asset	$ 323	$ (323)	$ -
11	ARO Regulatory Asset	$ -	$ 27	$ 27
	FUNDS FROM NON-INVESTORS			
12	Unamortized CIAC	$ (167,549)	$ (2,898)	$ (170,447)
13	Customer Advances	$ (822)	$ (57)	$ (879)
14	Customer Deposits	$ (6,377)	$ (221)	$ (6,598)
15	Accumulated Deferred Income Taxes	$ (155,081)	$ 23,976	$ (131,105)
16	Unamortized ITC & PV Tax Credit	$ (29,930)	$ 636	$ (29,294)
17	Unamortized Gain on Sales	$ (1,395)	$ (3)	$ (1,398)
18	Pension Liability	$ (101,942)	$ 101,942	$ -
19	OPEB Liability	$ (37,435)	$ 37,435	$ -
20	Working Cash (at present rates)	$ 24,122	$ (4,851)	$ 19,271
21	Rate Base at Present Rates	$ 1,216,188	$ (64,903)	$ 1,151,285
22	Working Cash (at proposed rates)	$ (1,876)	$ 1,311	$ (565)
23	**Rate Base at Proposed Rates**	$ 1,214,312	$ (63,592)	$ 1,150,720

Notes and Source

Col.A: HECO-2302 WP RateBase
Col.B: DOD-106
Col C: Col.A + Col.B

Hawaiian Electric Company, Inc.
Adjusted Net Operating Income
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	Per HECO (A)	DOD Adjustments (B)	Per DOD (C)
1	Electric Sales Revenue	$1,346,379	$ 59,499	$ 1,405,878
2	Other Operating Revenue	$ 3,391	$ (11)	$ 3,380
3	Gain on Sale of Land	$ 507	$ (7)	$ 500
4	TOTAL OPERATING REVENUES	$1,350,277	$ 59,481	$ 1,409,758
5	Fuel	$ 542,961	$ 913	$ 543,874
6	Purchased Power	$ 386,108	$ 764	$ 386,872
7	Production	$ 68,222	$ 1,738	$ 69,960
8	Transmission	$ 10,491	$ (113)	$ 10,378
9	Distribution	$ 24,722	$ 226	$ 24,948
10	Customer Accounts	$ 12,020	$ (91)	$ 11,929
11	Allowance for Uncollectibles	$ 1,358	$ 61	$ 1,419
12	Customer Service	$ 7,176	$ 94	$ 7,270
13	Administration and General	$ 72,007	$ (1,852)	$ 70,155
14	Gen Excise Tax Rate Incr Adj	$ 320	$ 8	$ 328
15	Operation and Maintenance	$1,125,385	$ 1,748	$ 1,127,133
16	Depreciation and Amortization	$ 79,736	$ (973)	$ 78,763
17	Amortization of State ITC	$ (1,321)	$ 17	$ (1,304)
18	Taxes Other Than Income	$ 126,151	$ 5,217	$ 131,368
19	Interest on Customer Deposits	$ 375	$ 2	$ 377
20	Income Taxes	$ (4,107)	$ 19,490	$ 15,383
21	TOTAL OPERATING EXPENSES	$1,326,219	$ 25,501	$ 1,351,720
22	**NET OPERATING INCOME**	**$ 24,058**	**$ 33,980**	**$ 58,038**

Notes and Source

Col.A: HECO-2302 "Present Rates" column
Col.B: DOD-111
Col.C: Col.A + Col.B

Hawaiian Electric Company, Inc.
Capital Structure and Cost Rates
Test Year Ending December 31, 2007

Exhibit DOD-105
Docket No. 2006-0386

Line No.	Description	Cost Rate (A)	Capital Ratio (B)	Weighted Cost (A) x (B) (C)	Pre-Tax Return (D)
	Per HECO (HECO-2302 WP)				
1	Short Term Debt	5.0000%	3.08%	0.154%	0.28%
2	Long Term Debt	6.0882%	38.01%	2.314%	4.16%
3	Hybrid Securities	7.4735%	2.18%	0.163%	0.29%
4	Preferred Stock	5.5134%	1.63%	0.090%	0.16%
5	Common Equity	11.2500%	55.10%	6.199%	11.15%
6	Total		100.00%	**8.92%**	16.04%
	Per DOD (Stephen G. Hill, DOD-215)				
7	Short Term Debt	5.0000%	5.72%	0.29%	0.52%
8	Long Term Debt	6.0900%	37.87%	2.31%	4.15%
9	Hybrid Securities	7.4700%	2.58%	0.19%	0.34%
10	Preferred Stock	5.5100%	1.82%	0.10%	0.18%
11	Common Equity	9.2500%	52.01%	4.81%	8.65%
12	Total		100.00%	**7.70%**	13.84%
13	Difference			-1.22%	-2.20%
14	Weighted Cost of Debt	Sum of Lines 7-9		2.79%	

Notes

		GRCF	Reference
Col.D:	Pre-Tax Return computed using GRCF	1.797979	DOD-102

Hawaiian Electric Company, Inc.
Summary of Adjustments to Rate Base
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	DOD Adjustments	HECO June 2007 Rate Base Updates	Accumulated Deferred Income Taxes "AFUDC on CWIP"	Cash Working Capital	Accumulated Deferred Income Taxes
			DOD-107	DOD-108	DOD-109	DOD-110
	INVESTMENT IN ASSETS SERVING CUSTOMERS					
1	Net Plant In Service	$ (16,084)	$ (16,084)			
2	Property Held for Future Use	$ (1,338)	$ (1,338)			
3	Fuel Inventory	$ 378	$ 378			
4	Materials & Supplies	$ -	$ -			
5	Unamortized Net SFAS 109 Regulatory Asset	$ (4,211)	$ (4,211)			
6	Prepaid Pension Asset	$ (161,188)	$ (101,783)	$ (59,405)		
7	Unamortized OPEB Regulatory Asset	$ (7,160)	$ (7,160)			
8	OPEB Regulatory Asset	$ (30,275)	$ (30,275)			
9	Unamortized System Development Costs	$ (688)	$ (688)			
10	Unamortized DSG Regulatory Asset	$ (323)	$ (323)			
11	ARO Regulatory Asset	$ 27	$ 27			
	FUNDS FROM NON-INVESTORS	$ -				
12	Unamortized CIAC	$ (2,898)	$ (2,898)			
13	Customer Advances	$ (57)	$ (57)			
14	Customer Deposits	$ (221)	$ (221)			
15	Accumulated Deferred Income Taxes	$ 23,976	$ 9,019	$ 23,114		$ (8,157)
16	Unamortized ITC	$ 636	$ 636			
17	Unamortized Gain on Sales	$ (3)	$ (3)			
18	Pension Liability	$ 101,942	$ 101,942			
19	OPEB Liability	$ 37,435	$ 37,435			
20	Working Cash (at present rates)	$ (4,851)	$ 2,149		$ (7,000)	
21	Rate Base at Present Rates	$ (64,903)	$ (13,455)	$ (36,291)	$ (7,000)	$ (8,157)
22	Working Cash (at proposed rates)	$ 1,311	$ 355		956	
23	Rate Base at Proposed Rates	$ (63,592)	$ (13,100)	$ (36,291)	$ (6,044)	$ (8,157)

Notes and Source

See referenced exhibit for each adjustment

Hawaiian Electric Company, Inc.
Adjusted Rate Base
Test Year Ending December 31, 2007

Line No.	Description		HECO As Filed (A)		HECO June 2007 Update Adjusted (B)		HECO June 2007 Updates Adjustment (C)
	INVESTMENT IN ASSETS SERVING CUSTOMERS						
1	Net Plant In Service	$	1,367,090	$	1,351,006	$	(16,084)
2	Property Held for Future Use	$	3,380	$	2,042	$	(1,338)
3	Fuel Inventory	$	52,706	$	53,084	$	378
4	Materials & Supplies	$	12,838	$	12,838	$	-
5	Unamortized Net SFAS 109 Regulatory Asset	$	54,628	$	50,417	$	(4,211)
6	Prepaid Pension Asset	$	161,188	$	59,405	$	(101,783)
7	Unamortized OPEB Regulatory Asset	$	7,160	$	-	$	(7,160)
8	OPEB Regulatory Asset	$	30,275	$	-	$	(30,275)
9	Unamortized System Development Costs	$	3,009	$	2,321	$	(688)
10	Unamortized DSG Regulatory Asset	$	323	$	-	$	(323)
11	ARO Regulatory Assett	$	-	$	27	$	27
	FUNDS FROM NON-INVESTORS						
12	Unamortized CIAC	$	(167,549)	$	(170,447)	$	(2,898)
13	Customer Advances	$	(822)	$	(879)	$	(57)
14	Customer Deposits	$	(6,377)	$	(6,598)	$	(221)
15	Accumulated Deferred Income Taxes	$	(155,081)	$	(146,062)	$	9,019
16	Unamortized ITC	$	(29,930)	$	(29,294)	$	636
17	Unamortized Gain on Sales	$	(1,395)	$	(1,398)	$	(3)
16	Pension Liability	$	(101,942)	$	-	$	101,942
17	OPEB Liability	$	(37,435)	$	-	$	37,435
	WORKING CASH						
18	Working Cash (at present rates)	$	24,122	$	26,271	$	2,149
19	Rate Base at Present Rates	$	1,216,188	$	1,202,733	$	(13,455)
20	Working Cash (at proposed rates)	$	(1,876)	$	(1,521)	$	355
21	**Rate Base at Proposed Rates**	$	1,214,312	$	1,201,212	$	(13,100)

Notes and Source

Col.A: HECO-2302 Workpapers RateBase
Col.B: HECO T-17 June 2007 Update - page 7 of 18, as further revised by HECO in DOD-IR-96
Col C: Col.B - Col.A

Hawaiian Electric Company, Inc.
Remove Net Pension Asset
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	Amount	Reference
	Net Pension Asset		
1	Amount per HECO update	$ (59,405)	Note a
2	Related Accum Def Inc Taxes	$ 23,114	Note b
3	Net Adjustment	$ (36,291)	

Notes and Source

(a) HECO T-17 June 2007 Update - page 7 of 18, as further revised by HECO in DOD-IR-96

(b) Per HECO's response to CA-IR-136 and CA-IR-441

ADIT	12/31/2006	12/31/2007	Average 2007
State & Federal	$ 26,560	$ 19,668	$ 23,114

Check of reasonableness, using Pension Asset amount and composite tax rate:

Pension Asset in HECO's June 2007 update	$ (59,405)
Composite tax rate	0.3891
Estimated ADIT related to Pension Asset	$ 23,114

Hawaiian Electric Company, Inc.
Remove Net Pension Asset
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Year	Beginning Pension Asset	FAS 87 Accrual	Trust Contribution	Ending Pension Asset	Average Pension Asset	Included In HECO Rates	
		(A)	(B)	(C)	(D)	(E)	(F)	
1	1987	$ 480,499	$ 9,216,777	$ 8,736,278	$ -	$ 240,250		
2	1988	$ -	$ 8,307,882	$ 8,307,882	$ -	$ -		
3	1989	$ -	$ 9,007,061	$ 9,007,061	$ -	$ -		
4	1990	$ -	$ 9,739,662	$ 9,739,662	$ -	$ -		
5	1991	$ -	$ 10,617,695	$ 10,617,695	$ -	$ -		
6	1992	$ -	$ 11,382,007	$ 11,382,007	$ -	$ -		
7	1993	$ -	$ 10,939,516	$ 10,939,516	$ -	$ -		
8	1994	$ -	$ 10,924,690	$ 10,924,690	$ -	$ -		
9	1995	$ -	$ 6,408,000	$ 9,058,124	$ 2,650,124	$ 1,325,062		
10	1996	$ 2,650,124	$ 8,380,584	$ 6,971,824	$ 1,241,364	$ 1,945,744	$ 9,499,000	
11	1997	$ 1,241,364	$ 7,117,179	$ 5,876,355	$ 540	$ 620,952	$ 9,499,000	
12	1998	$ 540	$ 1,870,595	$ 2,206,034	$ 335,979	$ 168,260	$ 9,499,000	
13	1999	$ 335,979	$ (1,073,259)	$ -	$ 1,409,238	$ 872,609	$ 9,499,000	
14	2000	$ 1,409,238	$ (19,322,692)	$ -	$ 20,731,930	$ 11,070,584	$ 9,499,000	
15	2001	$ 20,731,930	$ (20,465,117)	$ -	$ 41,197,047	$ 30,964,489	$ 9,499,000	
16	2002	$ 41,197,047	$ (15,655,436)	$ -	$ 56,852,483	$ 49,024,765	$ 9,499,000	
17	2003	$ 56,852,483	$ 5,894,495	$ 13,394,248	$ 64,352,236	$ 60,602,360	$ 9,499,000	
18	2004	$ 64,352,236	$ (1,546,921)	$ 15,186,494	$ 81,085,651	$ 72,718,944	$ 9,499,000	
19	2005	$ 81,085,651	$ 4,588,000	$ 6,000,000	$ 82,497,651	$ 81,791,651	$ 8,207,000	(d)
20	2006	$ 82,497,651	$ 14,237,000		$ 68,260,651	$ 75,379,151	$ 4,588,000	
21	2007	$ 68,260,651	$ 17,711,000		**$ 50,549,651**	$ 59,405,151	$ 4,588,000	
					Net (C) - (B)			
22	Totals		$ 88,278,718	$ 138,347,870	$ 50,069,152		$ 98,286,000	
							(a)	
23	1996-2005 Lines 10-19		$ (30,212,572)	$ 49,634,955	$ 79,847,527			
24	1996-2007 Lines 10-21		$ 1,735,428	$ 49,634,955	$ 47,899,527			
			(b)	(c)				

Estimated Net Amount "Provided" By Ratepayers, 1996-2007

Line	Description	Amount	Source
25	"Provided" by Ratepayers (amounts paid less HECO's recorded expense)	$ 96,550,572	(a) - (b)
26	"Provided" by HECO (funding contributions)	$ 49,634,955	(c)
27	**Net amount "provided" by Ratepayers**	**$ 46,915,617**	

Notes and Source
CA-IR-337 from Docket 04-0113 and HECO June 2007 update in current docket, HECO T-10, Att 10, page 2; HECO-1021
Col.B: FAS 87 accrual is referred to as "net periodic pension cost" or "NPPC" by HECO.
Col.F: NPPC from Docket 04-0113 and HECO's response to CA-IR-158
Lines 22 and 24 are the estimated amount paid by ratepayers less the expense recorded by HECO.
(d) Interim Decision in Docket 04-0113 effective 9/27/05; pro ration of 2005 amount:

	From	To	Days	Annual	2005
From 12/31/04 to 9/26/05	12/31/04	9/26/2005	269	$ 9,499,000	$ 7,000,633
From 9/26/05 to 12/31/05	9/26/2005	12/31/2005	96	$ 4,588,000	$ 1,206,707
			365		$ 8,207,340

Per HECO, average TY Prepaid Pension Asset: $ 59,405,151 DOD-IR-96, page 3 of 5; also average of Col.D, L20&21

Hawaiian Electric Company, Inc.
Cash Working Capital
(Thousands of Dollars)
Test Year Ending December 31, 2007

DOD-109
Docket No. 2006-0386

Line No.	Description	Revenue Collection Lag (Days)	Payment Lag (Days)	Net Collection Lag (Days) (A) - (B)	Annual Amount (See Below)	Average Daily Amount - Present (D) / 365	Working Cash Required (Provided) under Present Rates (C) x (E)	Average Daily Amount - Proposed (D) / 365	Working Cash Required (Provided) under Proposed Rates (C) x (G)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	ITEMS REQUIRING WORKING CASH:								
1	Fuel Purchases	37	17	20	$ 537,767	$ 1,473	$ 29,460	$ 1,473	$ 29,460
2	O&M Labor	37	11	26	$ 89,202	$ 244	$ 6,344	$ 244	$ 6,344
3	O&M Nonlabor	37	50	(13)	$ 118,049	$ 323	$ (4,269)	$ 323	$ (4,269)
4	Pension Asset Amortization (Note a)								
	ITEMS PROVIDING WORKING CASH:								
5	Purchased Power	37	39	(2)	$ 386,872	$ 1,060	$ (2,120)	$ 1,060	$ (2,120)
6	Revenue Taxes - Present Rates	37	66	(29)	$ 125,002	$ 342	$ (9,918)		
7	Revenue Taxes - Proposed Rates	37	66	(29)	$ 129,870			$ 356	$ (10,324)
8	Income Taxes - Present Rates	37	40	(3)	$ 27,257	$ 75	$ (225)		
9	Income Taxes - Proposed Rates	37	40	(3)	$ 46,726			$ 128	$ (384)
10	**WORKING CASH ALLOWANCE - CALCULATEI**						$ 19,272	Change:	$ 18,707
11	CHANGE IN WORKING CASH							$ (565)	
12	**WORKING CASH ALLOWANCE - HECO June 2007 update, per DOD-IR-97, page 2 of 3**						$ 26,272	$ (1,521)	$ 24,751
13	**ADJUSTMENT TO WORKING CASH AND CHANGE IN WORKING CASH**						$ (7,000)	$ 956	$ (6,044)

Derivation of Annual Expense Amounts for Column D:

Line	Component	Amounts per DOD-IR-97	Adjustments	Reference	Adjusted Amounts	Posted To Col.D	Revenue Incr. Amounts DOD-101	Amounts At Proposed Rates	To Col.D
		(I)	(J)	(K)	(L)		(M)	(N)	
14	Fuel Expense	$ 537,767			$ 537,767	Line 1			
15	O&M Labor	$ 89,202			$ 89,202	Line 2			
16	O&M Non-Labor	$ 118,932	$ (883)	Note c	$ 118,049	Line 3			
17	Purchased Power	$ 386,872			$ 386,872	Line 5			
18	Pension Asset Amortization	$ 5,055	$ (5,055)	DOD-114 & (b)	$ -				
19	Revenue Tax	$ 119,918	$ 5,084	DOD-111 &DOD-114	$ 125,002	Line 6	$4,868	$129,870	Line 7
20	Income Tax	$ 5,240	$ 22,017	DOD-111, L.21 Adj DOD-113 - 122	$ 27,257	Line 8	$19,469	$46,726	Line 9

(a) HECO's proposal to include amortizaton of a Pension Asset in cash working capital at a zero lag should be rejected in total
As explained in the testimony that is not an appropriate operating expense and is not an appropriate component of cash working capital.

(b) HECO's June 2007 update adjustments to expenses appear to have already been reflected in the DOD-IR-97 amounts in Col.I above.
So the adjustments in Column J are for the DOD adjustments on DOD-111 for adjustments other than the HECO June 2007 update.

(c) DOD-115, 116, 117 and 12; also DOD-111, L.26

Line	Description	Test Year Expense ($000's) Note A	% of Total	Total Payment Lag Days	Reference	Weighted Average
1	Pension Expense[1]	$12,929	11%	182.5	Testimony	20 days
2	OPEB Expense[2]	$4,636	4%	84.8	June 2007 Update HECO T-17, p.15.	3 days
3	Regulatory Commission Expense[4]	$320	0%	30.3	Normal non-labor O&M lag applied	0 days
4	Emission Fees[5]	$691	1%	305.5	HECO-WP-1706, p. 33-36	2 days
5	EPRI Dues[6]	$1,608	1%	-6.6	HECO-WP-1706, p. 33-36	0 days
6	Other Non-Labor O&M[7]	$97,974	83%	30.3	HECO-WP-1706, p. 33-36	25 days
7		$118,157	100%			
8	**O&M Non-Labor Payment Lag**					**50 days**
	Non-cash amortizations excluded:					
9	System Devel. Costs Amortization[3]	$158	0%	N/A	Exclude non-cash amortization	N/A
10	Waiau Water Well Amortization[5]	$296	0%	N/A	Exclude non-cash amortization	N/A
11	Kahe Unit 7 Amortization[5]	$321	0%	N/A	Exclude non-cash amortization	N/A
		$118,932				

Notes and HECO's references

[A] Totals may not add exactly due to rounding.

[1] Pension expense estimate based on 2007 Pension Accrual of $17,710k (per June 2007 Update HECO T-12) x 73% (based on 2006 % of Employee Benefits charged to O&M expense).

[2] OPEB expense estimate based on 2007 OPEB expense of $6,350k (per June 2007 Update HECO T-12) x 73% (based on 2006 % of Employee Benefits charged to O&M expense). Includes $1,302k of SFAS 106 Reg. Asset amortization.

[3] June 2007 Update, HECO T-10, Attachment 5

[4] June 2007 Update, HECO T-13, page 6.

[5] HECO T-6 or June 2007 Update, HECO T-6.

[6] EPRI Dues per HECO-1304

[7] Other Non-Labor O&M = Total O&M Non-Labor expense of $118,932k, less other items noted above.

Hawaiian Electric Company, Inc.
Accumulated Deferred Income Taxes "AFUDC on CWIP"
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	12/31/2006 Amount	12/31/2007 Amount	Average
		(A)	(B)	(C)
	Accumulated Deferred Income Taxes For "AFUDC in CWIP"			
1	Federal	$ (6,591)	$ (7,201)	$ (6,896)
2	State	$ (1,205)	$ (1,317)	$ (1,261)
3	Total	$ (7,796)	$ (8,518)	$ (8,157)

Notes and Source

Negative amounts indicate rate base deduction (credit)
Postive amounts indicate rate base increase (debit)
Col.A: CA-IR-306 and June 2007 Update, HECO T-15 Supplemental Filing, HECO-WP-1505
Col.B: June 2007 Update, HECO T-15 Supplemental Filing (dated 7/25/2007), HECO-WP-1505
Note: amounts provided in CA-IR-469, page 3 of 3 are slightly different.

"AFUDC in CWIP"	
Federal	$ (7,009)
State	$ (1,282)
Total	$ (8,291)

Hawaiian Electric Company, Inc.
Adjusted Net Operating Income
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	DOD Adjustments	HECO June and July 2007 Updates DOD-112	Revenues, Known Rate Changes DOD-113	Remove Amortization of Pension Asset DOD-114	Edison Electric Institute Expense DOD-115	Security Services Expense DOD-116	"Community Process" Expenses DOD-117	Income Taxes - Interest Synchronization DOD-118	Research, Development and Demonstration Expense in Miscellaneous O&M DOD-122
1	Electric Sales Revenue	$ 59,499	$ 2,256	$ 57,243						
2	Other Operating Revenue	$ (11)	$ (62)	$ 51						
3	Gain on Sale of Land	$ (7)	$ (7)							
4	TOTAL OPERATING REVENUES	$ 59,481	$ 2,187	$ 57,294	$ -	$ -	$ -	$ -	$ -	$ -
5	Fuel	$ 913	$ 913							
6	Purchased Power	$ 764	$ 764							
7	Production	$ 1,738	$ 1,855				$ (117)			
8	Transmission	$ (113)	$ (113)							
9	Distribution	$ 226	$ 226							
10	Customer Accounts	$ (91)	$ (91)							
11	Allowance for Uncollectibles	$ 61	$ 3	$ 58						
12	Customer Service	$ 94	$ 94							
13	Administration and General	$ (1,852)	$ 3,969		$ (5,055)	$ (61)		$ (330)		$ (375)
14	Gen Excise Tax Rate Incr Adj	$ 8	$ 8							
15	Operation and Maintenance	$ 1,748	$ 7,628	$ 58	$ (5,055)	$ (61)	$ (117)	$ (330)	$ -	$ (375)
16	Depreciation and Amortization	$ (973)	$ (973)							
17	Amortization of State ITC	$ 17	$ 17							
18	Taxes Other Than Income	$ 5,217	$ 133	$ 5,084						
19	Interest on Customer Deposits	$ 2	$ 2							
20	Expense Before Income Taxes	$ 6,011	$ 6,807	$ 5,142	$ (5,055)	$ (61)	$ (117)	$ (330)	$ -	$ (375)
21	Income Taxes	$ 19,490	$ (2,527)	$ 20,293	$ 1,967	$ 24	$ 46	$ 128	$ (587)	$ 146
22	TOTAL OPERATING EXPENSES	$ 25,501	$ 4,280	$ 25,435	$ (3,088)	$ (37)	$ (71)	$ (202)	$ (587)	$ (229)
23	**NET OPERATING INCOME**	$ 33,980	$ (2,093)	$ 31,859	$ 3,088	$ 37	$ 71	$ 202	$ 587	$ 229

Notes and Source

Line 20: Combined tax rate for calculating impact on Income Taxes 38.91% DOD-102 and HECO-WP-2301, pp.10 & 11

Subtotals Carried to Cash Working Capital Calculation on DOD-109:

24	Pension asset amortization	$ (5,055)	Line 13, DOD-114
25	Income tax adjustments other than HECO June 2007 update	$ 22,017	Line 21, DOD-113 through DOD-122
26	O&M Expense adjustments DOD-114 through DOD-122	$ (883)	Line 15, DOD-115 through DOD-122

Hawaiian Electric Company, Inc.
HECO June and July 2007 Updates
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	Per HECO (A)	HECO June 2007 Updates (B)	HECO June 2007 Update References	HECO June 2007 Update Adjustment (C)
1	Electric Sales Revenue	$1,346,379	$ 1,348,635	T-3	$ 2,256
2	Other Operating Revenue	$ 3,391	$ 3,329	DOD-IR-95	$ (62)
3	Gain on Sale of Land	$ 507	$ 500	DOD-IR-95	$ (7)
4	TOTAL OPERATING REVENUES	$1,350,277	$ 1,352,464		$ 2,187
5	Fuel	$ 542,961	$ 543,874	T-4	$ 913
6	Purchased Power	$ 386,108	$ 386,872	T-5	$ 764
7	Production	$ 68,222	$ 70,077	DOD-IR-95	$ 1,855
8	Transmission	$ 10,491	$ 10,378	T-7	$ (113)
9	Distribution	$ 24,722	$ 24,948	T-7	$ 226
10	Customer Accounts	$ 12,020	$ 11,929	T-8	$ (91)
11	Allowance for Uncollectibles	$ 1,358	$ 1,361	T-8	$ 3
12	Customer Service	$ 7,176	$ 7,270	T-9	$ 94
13	Administration and General	$ 72,007	$ 75,976	T-10	$ 3,969
14	Gen Excise Tax Rate Incr Adj	$ 320	$ 328	DOD-IR-95	$ 8
15	Operation and Maintenance	$1,125,385	$ 1,133,013		$ 7,628
16	Depreciation and Amortization	$ 79,736	$ 78,763	T-13	$ (973)
17	Amortization of State ITC	$ (1,321)	$ (1,304)	T-15	$ 17
18	Taxes Other Than Income	$ 126,151	$ 126,284	DOD-IR-95	$ 133
19	Interest on Customer Deposits	$ 375	$ 377	T-8	$ 2
20	Income Taxes	$ (4,107)	$ (6,634)	DOD-IR-95	$ (2,527)
21	TOTAL OPERATING EXPENSES	$1,326,219	$ 1,330,499		$ 4,280
22	**NET OPERATING INCOME**	**$ 24,058**	**$ 21,965**		**$ (2,093)**

Notes and Source

Col.A: HECO-2302 "Present Rates" column
Col.B: DOD-IR-95
Col.C: Col.B - Col.A

Hawaiian Electric Company, Inc.
Revenues, Known Rate Changes
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	HECO As-Filed Amount (A)	HEC Update Amount (B)	Difference (C)	DOD Adjusted (D)	DOD Adjustment (E)
1	Revenue at current effective rates	$ 1,398,279	$ 1,404,092	$ 5,813	$ 1,405,878 (a)	
2	Revenue at present rates	$ 1,346,379	$ 1,348,635	$ 2,256	$ 1,348,635	
3	Additional revenue at current rates	$ 51,900	$ 55,457	$ 3,557	$ 57,243	$ 57,243
	Spread of HECO's Adjustment by Component:					
	Revenue:		From Page 2:		DOD Adjustment	
4	Electric Sales Revenue		$ 55,457		$ 57,243	$ 57,243
5	Other Operating Revenue		$ 49	-0.08836%	$ 51	$ 51
	Expenses:					
6	Allowance for Uncoll. Accounts		$ 56	0.10098%	$ 58	$ 58
7	Taxes Other Than Income		$ 4,925	8.88075%	$ 5,084	$ 5,084
8	Income Taxes		$ 19,660	35.45089%	$ 20,293	$ 20,293
9	OPERATING INCOME		$ 30,865	55.65573%	$ 31,859	$ 31,859
10	Percent of Electric Sales Revenue			100.00000%		

Notes and Source

Cols.A&B: HECO June 2007 Update, HECO T-3, pages 4 et seq of 41, Supplemental

(a) Derivation of revenue at current effective rates:

Line No.	Interim Surcharge Revenue	Per HECO 8/12ths	Per DOD Annual Amount	Difference	
	Rate Schedule:				
11	R	$ 985.0	$ 1,477.5	$ 492.5	
12	G	$ 172.0	$ 258.0	$ 86.0	
13	J	$ 957.2	$ 1,435.8	$ 478.6	
14	H	$ 18.7	$ 28.1	$ 9.4	
15	PS	$ 386.7	$ 580.1	$ 193.4	
16	PP	$ 954.0	$ 1,431.0	$ 477.0	
17	PT	$ 81.0	$ 121.5	$ 40.5	
18	F	$ 17.5	$ 26.3	$ 8.8	
19	Total	$ 3,572.1	$ 5,358.3	$ 1,786.2	
20	HECO calculated revenue at current rates			$ 1,404,092	Line 1, Col.B
21	DOD calculated revenue at current rates			$ 1,405,878	

Alternative Calculation to Confirm Reasonableness:

Line No.	Description	Amount		Difference
22	Annual Substation DG fuel expense	$ 3,805		
23	Annual Honolulu LSFO Trucking Expense	$ 906		
24	Annual Substation DG Trucking Expense	$ 168		
25	Total	$ 4,879		
26	Revenue Tax Factor	1.0975		
27	Annualized	$ 5,355	$ 5,358.3	$ 3.30

Hawaiian Electric Company, Inc.
Base Case at Current Effective Rates Versus at Present Rates
Results of Operations
($ Thousands)

Line	Description	Present Rates HECO Update HECO-WP-2302 Additional Amount	Current Effective Rates HECO Update HECO-WP-2301 Additional Amount	Difference
		(A)	(B)	(C)
1	Electric Sales Revenue	$ 1,348,635	$ 1,404,092	$ 55,457
2	Other Operating Revenue	$ 3,329	$ 3,378	$ 49
3	TOTAL OPERATING REVENUES	$ 1,351,964	$ 1,407,470	$ 55,506
4	Allowance for Uncoll. Accounts	$ 1,361	$ 1,417	$ 56
5	Operation and Maintenance	$ 1,361	$ 1,417	$ 56
6	Taxes Other Than Income	$ 126,284	$ 131,209	$ 4,925
7	Income Taxes	$ (6,634)	$ 13,026	$ 19,660
8	TOTAL OPERATING EXPENSES	$ 121,011	$ 145,652	$ 24,641
9	OPERATING INCOME			$ 30,865

Hawaiian Electric Company, Inc.
Remove Amortization of Pension Asset
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	Amount	Reference
1	Pension Asset Amortization	$ (5,055)	HECO June 2007 update DOD-IR-98

Hawaiian Electric Company, Inc.
Edison Electric Institute Dues

Test Year Ending December 31, 2007

Line No.	Description	Total Amount (A)	HECO Exclusion (B)	DOD Exclusion (C)		DOD Adjusted (D)	DOD Adjustment (E)
1	EEI regular dues	$ 244,580	$ (61,145)	$ (122,111)	(a)	$ 122,469	$ (60,966)
2	EEI Industry Structure Assessment	$ 36,687	$ (25,681)	$ (25,681)	(b)	$ 11,006	$ -
3	EEI Mutual Assistance Program	$ 3,342			(c)	$ 3,342	$ -
4	Total 2007 EEI dues	$ 284,609	$ (86,826)	$ (147,792)		$ 136,817	$ (60,966)
5							
	Percentage Exclusion:						
6	EEI regular dues		-25%	-49.93%	See page 2		
7	EEI Industry Structure Assessment		-70%	-70%			
8	EEI Mutual Assistance Program		0%	0%			
9	Total		-31%	-52%			

Notes and Source

Col.A&B: DOD-IR-125

(a) HECO failed to provide the breakout of EEI dues into the NARUC specified categories, which was requested in DOD-IR-127e
Consequently, the most recent available breakout into such categories (shown on page 2) was used to compute the disallowance.

10	EEI regular dues	$ 244,580	
11	Disallowance percentage	49.93%	Page 2
12	DOD recommended disallowance	$ 122,111	

(b) In lieu of removing 100% of this voluntary extra payment to EEI, HECO's exclusion of 70% is accepted. For 2005, EEI designated 70% of its Separately Funded Activities (SFA) for Industry Structure as non-deductible. HECO's response to DOD-IR-127d asserted that: "There have been no communications with EEI in 2006 and 2007 related to influencing legislation and EEI dues-funded activities that are considered 'non-deductible' for federal income tax purposes."

(c) This component of the payment to EEI is a voluntary payment approved by the EEI Executive Committee relating to improvements for the electric utility industry's rapid response to disasters.

Test Year Ending December 31, 2007

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core (Regular) Dues Activities
For the Year Ended December 31, 2005

Line	NARUC Operating Expense Category	% of Dues	Recommended Disallowance
1	Legislative Advocacy	20.38%	20.38%
2	Legislative Policy Research	6.02%	
3	Regulatory Advocacy	16.49%	16.49%
4	Regulatory Policy Research	13.99%	
5	Advertising	1.67%	1.67%
6	Marketing	3.68%	3.68%
7	Utility Operations and Engineering	11.31%	
8	Finance, Legal, Planning and Customer Service	18.75%	
9	Public Relations	7.71%	7.71%
10	Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2005, the lobbying % for IRS reporting is 19.4%.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

Hawaiian Electric Company, Inc.
Security Services Expense

Test Year Ending December 31, 2007

Line No.	Description	Amount	Reference
	Security Services Expense:		
1	2007 Expense through June 2007 Excluding 2006 Invoices	$ 266,604	CA-IR-486, p.2
2	HECO's estimate of outstanding invoices for the remainder of June 2007	$ 40,072	CA-IR-486, p.3
3	Total 2007 through June	$ 306,676	CA-IR-486, p.3
4	June 2007 annualized	$ 613,352	
5	HECO's test year estimate	$ 730,280	CA-IR-486, p.3
6	Adjustment for security services expense	$ (116,928)	

Hawaiian Electric Company, Inc.
"Community Process" Expenses

Test Year Ending December 31, 2007

Line No.	Description	Amount	Reference
1	Outside Services General for "Community Process"	$ 660,000	Note A
2	Allocation between ratepayers and shareholders	50%	Testimony
3	Remove portion of "Community Process" expense allocated to shareholders	$ (330,000)	

Notes

[A] Per response to CA-IR-372, page 2, the $660,000 is for "political and community involvement."
This is also referred to as "Community Process" expenditures.
Also see responses to CA-IR-2 (HECO T-10, Attachment 26, page 2), CA-IR-288, and DOD-IR-128 and DOD-IR-129.

Hawaiian Electric Company, Inc.
Interest Synchronization Adjustment
(Thousands of Dollars)
Test Year Ending December 31, 2007

DOD-118
Docket No. 2006-0386
Page 1 of 1

Line No.	Description	Amount	Reference
	I. Adjustment on HECO's Direct Filing		
1	Adjusted Rate Base	$ 1,150,720	DOD-103
2	Weighted Cost of Debt	2.79%	DOD-105
3	Synchronized Interest Expense	$ 32,105	Line 1 x Line 2
4	HECO "As Filed" Interest Expense	$ 30,587	HECO-1502 & HECO-WP-1502
5	Net Adjustment to Interest Expense	$ 1,518	
6	Combined State/Federal Tax Rate	38.91%	DOD-102
7	Interest Synchronization Adjustment, Reduction to Income Tax Expense	$ (591)	
	II. Adjustment on HECO's Update Filing		
8	Adjusted Rate Base	$ 1,150,720	DOD-103
9	Weighted Cost of Debt	2.79%	DOD-105
10	Synchronized Interest Expense	$ 32,105	Line 1 x Line 2
11	HECO "As Filed" Interest Expense	$ 30,596	Note a
12	Net Adjustment to Interest Expense	$ 1,509	
13	Combined State/Federal Tax Rate	38.91%	DOD-102
14	Interest Synchronization Adjustment, Reduction to Income Tax Expense	$ (587)	To DOD-111

Notes

(a) HECO June 2007 update, HECO T-15, Supplemental Filing, page 13 of 19, HECO-1502 & HECO-WP-1502

Hawaiian Electric Company, Inc.
Adjust Income Tax Expense for Short Term Debt
(Thousands of Dollars)
Test Year Ending December 31, 2007

Line No.	Description	Per HECO Amount (A)	Per DOD Amount (B)	Difference (C)
1	Short term debt	$ 38,971	$ 70,052	$ 31,081
2	Interest rate for short term debt	5.00%	5.00%	
3	Interest on short term debt	$ 1,949	$ 3,503	$ 1,554
4	Combined State/Federal Tax Rate	38.91%	38.91%	38.91%
5	Reduction to Income Tax Expense	$ 758	$ 1,363	$ 605

Notes and Source

This adjustment should be made only if Interest Synchronization, as shown on DOD-118, is NOT used.

Col.A:

L1-3: HECO June 2007 Update for HECO T-15, Supplemental Filing, page 13 of 19

Col.B:

L.1: DOD-205, page 1 (Stephen Hill)

Alternative derivation of short-term debt amount based on capital structure ratios:

6	Short term debt amount per HECO	$ 38,971	Note a
7	Short term debt percent in capital structure per HECO	3.08%	DOD-105
8	Short term debt percent in capital structure per DOD	5.72%	DOD-102 and DOD-215
9	Short term debt amount per DOD	$ 72,375	

(a) HECO June 2007 Update for HECO T-15, Supplemental Filing, page 13 of 19

L.2: DOD-215 and DOD-105

Col.A&B:

L.3: Line 1 x Line 2

L.4: DOD-102

L.5: Line 3 x Line 4

This Company-proposed adjustment is intended to restate the test year rate base and depreciation expense associated with Allowance for Funds Used During Construction (AFUDC) accrued in a side record related to short term Construction Work in Progress (CWIP).

Commission Staff proposes to offset the Company's adjustment with deferred taxes based upon its theory that depreciation of AFUDC must generate a reduction in deferred taxes. The Company responds that in order to have a tax effect of depreciation there must be revenue. It cites Ms. Wright's testimony that nonoperating revenues generated these deferred taxes, and it reasons that because the deferred taxes were "below the line", depreciation of the AFUDC cannot generate above-the-line deferred taxes. The Commission finds that the Company's explanation is correct.

The Commission accepts the Company's adjustment to its side record, which drew no objection, and finds that the Commission Staff-proposed adjustment to deferred taxes is inappropriate.

G. Interest Synchronization, C-16.

Public Counsel/TRACER witness Carver proposes an interest synchronization adjustment, generally referred to as pro forma debt in prior Commission orders, to pro form the effect of the Commission's authorized weighted cost of debt on the Company's Federal Income Tax (FIT) expense. His adjustment determines a level of pro forma interest by multiplying his pro forma rate base times Mr. Hill's weighted cost of debt.

Mr. Carver notes the absence of an interest synchronization adjustment in Staff's case. He states that it is important to adjust the interest expense effect on o the level of interest that the ratepayer is required to pay through the rate of return.

Staff accepts this adjustment in principle, with one modification. That modification is to include interest on CWIP as part of pro forma interest. Public Counsel/TRACER accept the Commission Staff revision for the inclusion of CWIP in the calculation.

The Company argues that it is inappropriate to use a hypothetical capital structure and therefore it is inappropriate to make a pro forma adjustment to interest. The Company's argument appears groundless. Even the Company's original weighted cost of debt was based on a capital structure and cost of debt from one point in time and not exactly equal to test year averages. Further, as Mr. Carver testified (TR 2416-2417), USWC had unamortized investment tax credit on its books during the test period. Investment tax credits are not subtracted from rate base, as are accumulated deferred taxes. USWC as an "option 2" company under tax regulations is allowed to earn its authorized return on the unamortized portion of these credits. The return is to be equal to the overall return found appropriate by this Commission. As Mr. Carver testified, the regulator is allowed to synchronize the tax benefits of the assumed interest costs allowed to USWC. Therefore, in order to represent correctly the tax benefits of interest to be paid for by the ratepayers, and allowed by current tax regulations, the Commission accepts Mr. Carver's proposed adjustment. The Commission has recalculated this adjustment based on the findings in this record, and the effect is an increase to NOI of $4,925,548.

Commission Staff proposed to include CWIP in the calculation of pro forma interest. The Commission notes that there is no testimony supporting Staff's modification. The Commission is aware that in many previous orders CWIP was included in the calculation to the extent companies were not required to capitalize interest for tax purposes. As there is no evidence to support this modification in this proceeding, it follows that the Commission will exclude CWIP from the calculation.

Excluding CWIP from the calculation raises the concern of how tax benefits of interest on construction will be flowed through to the ratepayers. In this proceeding only, the Company will be authorized to normalize the tax benefits of interest associated with CWIP, if they exist, by accruing AFUDC on projects when interest is not capitalized for tax purposes, at the authorized return net of tax rather than at the authorized return. This is the same method used to calculate the allowance for funds used to conserve energy (AFUCE) for Puget Sound Power and Light.[39]

H. Uncontested Adjustments

The following adjustments are uncontested and are accepted as portrayed: Adjustments RMA-1, 2, and 4 through 7; RSA-4, 6, 8, 9, 11, and 15; RSA 17-OOP-1, 3, and 5 through 8; PFA-12; and SA-10.

VI. RATE BASE

The parties disagreed on a number of matters relating to calculation of the Company's proper rate base for regulatory purposes. The differences are shown in the Table attached to this Order as an Appendix, as set out in Public Counsel's brief.

A. Working Capital, Adjustments PFA-3, PFA-4, PFA-5, & SA-7

The Company proposes three components of working capital: pension asset, cash working capital (lead lag study), and materials and supplies.

1. Pension Asset

The Company proposes to include the pension asset as a discrete item in rate base. Ms. Wright discusses the pension asset adjustment, PFA-3, which increases rate base by $69.9 million.

---

[39] See, WUTC v. Puget Sound Power & Light, Cause Nos. U-90-1183 and -1184, 3d and 4th Supp. Orders.

It should be noted that the Section 203(e) requirements apply only to "protected" deferred tax reserves--those to which the normalization requirements of the Internal Revenue Code apply. Other excess deferred tax reserves may be returned by a utility more rapidly than over the average remaining lives of the assets, if so ordered by its respective regulators.

Many smaller utilities lack the extensive vintage property records necessary to make calculations in accordance with the ARAM procedure. As a result, a special alternative procedure has been authorized by the IRS for such taxpayers. This has become known as the "Reverse South Georgia Method" in reference to a methodology found acceptable by FERC for adjusting deferred tax reserve deficiencies in a past rate case involving South Georgia Natural Gas Company. As illustrated on Exhibit No. 17, the alternative calculation is based on a determination of the difference between the actual recorded ADIT balance as of a particular measurement date and the hypothetical balance that would have existed, had the new tax rate always been used for providing deferred income taxes. Such difference is divided by the estimated remaining book lives of the respective assets, to arrive at an annual amortization amount to be deducted from future deferred tax provisions.

3. Interest Synchronization. One amount that must be determined in calculating the Current Income Tax Expense component of the Cost of Service is the deduction for interest. As previously stated, because interest expense is a component of the return (net operating income) and not included in operating expenses, it is treated as a Schedule M item in deriving taxable income for ratemaking purposes.

Using the amount of interest expense recorded during the test year as the tax deduction for ratemaking is generally not appropriate. Frequently, the dollars of capitalization are different from rate base. This occurs for a variety of reasons. There may be capital invested in assets that are not included in rate base (i.e., CWIP or non-regulated assets) or investments in other jurisdictions. There also may be sources of capital for rate base investment, other than the debt and equity reported in capital structure, such as the funds provided through the Investment Tax Credit. Because of the difference that typically exists between rate base and capital structure, it has been necessary to perform various annualizations and allocations of interest expense in deriving taxable income.

During the 1970s the Staff of the FERC introduced a concept labeled "interest synchronization," under which the interest deduction for taxes in ratemaking was computed by multiplying the weighted cost of debt in capital structure by the net rate base. An example was previously presented on Exhibit No. 6. The idea was simple--the interest deduction for taxes should be the amount of interest implicit in revenue requirements. This approach was soon adopted by a number of the states for ratemaking in their respective jurisdictions.

Despite its apparent simplicity, the concept of interest synchronization became one of the most controversial issues in ratemaking during the 1980s. The thrust of the controversy was that, for most utilities, it resulted in reduced revenue requirements. For many companies, the funding for a substantial portion of their rate base was the Investment Tax Credit. Because most had selected Option 2 ratemaking treatment (cost of service reduction for the amortization of ITC, but no rate base reduction for Unamortized ITC), the effect of interest synchronization was to impute a hypothetical interest deduction for that portion of its return on rate base attributable to the Credit. This is illustrated on Exhibit No. 18.

Those opposed to interest synchronization alleged that such treatment was contrary to the normalization requirements of the Internal Revenue Code, and thus, put at risk the utilities' ability to continue to obtain benefits of the Credit. Specifically, the objectors pointed to the Internal Revenue Service Regulations covering the prescribed ratemaking treatment of ITC under Option 2. The rules state that the Credit will be disallowed if either the cost of service for ratemaking purposes is reduced by more than a ratable portion of the Credit, or the rate base is reduced by any portion of the credit.

It was argued that synchronizing the interest of an Option 2 company was tantamount to reducing cost of service by more than a ratable portion.

The controversy over interest synchronization existed for several years. Several FERC rate decisions in which interest was synchronized were appealed to the Courts by the respective utilities on the grounds that the Commission's orders placed the companies' Investment Credits in jeopardy. In each instance, the Appeals Court upheld the FERC decision. Nevertheless, the controversy continued.

In 1985, the IRS finally agreed to clarify its position on the matter of interest synchronization. After extensive consideration, it issued Treasury Decision 8089 in May, 1986. That document contained final regulations clearly indicating that interest synchronization was not a violation of the Internal Revenue Code for utilities that selected Option 2 for ratemaking. The IRS concluded that synchronization of interest does not result in a reduction of cost of service that is attributable to the Credit. That conclusion was based on the presumption similar to the reasoning underlying the aforementioned decisions of the appeals Court, that:

> "In the absence of the credit, the additional capital needed to finance investment property generally would be obtained from a similar proportion of debt and equity as in the existing capital structure of the utility. Synchronization of interest properly takes into account the additional interest expense that would have been incurred in those circumstances."

4. **Sale, Transfer, or Deregulation of Public Utility Property.** When public utility assets are sold, transferred to non-utility operations, or otherwise removed from regulated rate base, questions frequently arise with respect to the continuing applicability of the Tax Code's normalization rules, particularly with respect to the recognition of the related ADIT balances or Unamortized Investment Tax Credits in determining the utility's revenue requirements. In recent years there have been numerous IRS rulings indicating that the normalization rules generally restrict the flow back of such benefits to ratepayers in such circumstances. To continue to reduce rate

INCOME TAXES IN RATEMAKING

	(Before any Rate Change) Company	Staff
Rate Base	$12,000	$11,000
Revenues	$ 9,000	$ 9,500
Expenses (before Inc. Taxes)	7,800	6,000
Interest Exp. For Income Taxes	**336**	**440**
Taxable Income	$ 864	$3,060
Tax Rate	40%	40%
Income Tax Expense	$ 346	$1,224

INCOME TAXES – SYNCHRONIZED INTEREST

Company

Debt	35% @ 8% =	.0280
Equity	65% @ 13%=	.0845
Total		11.25%
Rate Base		$12,000
Wted. Cost of Debt		2.8%
Synchronized Interest		**$336**

Staff

Debt	50% @ 8% =	.04
Equity	50% @ 10%=	.05
Total		9.0%
Rate Base		$11,000
Wted. Cost of Debt		4%
Synch. Interest		**$440**

SYCHRONIZED INTEREST

- Synchronized Interest – for Computing Taxes
  - Matching Interest to the Rate Base and Capital Structure Used for Ratemaking
  - Only allow interest on the portion of the Debt that is necessary to support the rate base (or investment necessary to provide the utility service)

Hawaiian Electric Company, Inc.
Research, Development and Demonstration Expense in Miscellaneous O&M
(Thousands of Dollars)
Test Year Ending December 31, 2007

DOD-122
Docket No. 2006-0386

Line No.	Description	Amount	Reference
	Normalize Miscellaneous (Non-EPRI) RD&D:		
1	HECO's estimated 2007 R&D within Miscellaneous O&M	$ 1,156	Note A
2	Normalized amount based on 3-year average:	$ 781	Note B
3	Adjustment to normalize Miscellaneous RD&D Expense	$ (375)	Line 2 - Line 1

Notes

[A} Per CA-IR-452, page 2, and June 2007 Update for HECO T-13, pages 7 and 8 of 24.

[B] Non-EPRI RD&D in Miscellaneous O&M Expense

Year	Amount	Reference
2005	$ 865	CA-IR-452, page 2
2006	$ 323	CA-IR-452, page 2
2007	$ 1,156	CA-IR-452, page 2 & T-13 Update
Three-Year Average	$ 781	

CERTIFICATE OF SERVICE

I hereby certify that one copy of the foregoing TESTIMONY OF RALPH C. SMITH, CPA, ON BEHALF OF THE DEPARTMENT OF DEFENSE was duly served upon the following parties, by personal service, hand-delivery, and/or U.S. mail, postage prepaid, and properly addressed pursuant to HAR sec. 6-61-21(d).

William A. Bonnet
Vice President, Government and Community Affairs
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawaii 96840-0001

Dean K. Matsuura — 2 Copies
Director, Regulatory Affairs
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawaii 96840-0001

Thomas W. Williams, Jr., Esq.
Peter Y. Kikuta, Esq.
Goodsill Anderson Quinn & Stifel
1800 Alii Place
1099 Alakea Street
Honolulu, Hawaii 96813

Department of Commerce and Consumer Affairs — 6 Copies
State of Hawaii
Division of Consumer Advocacy
335 Merchant Street, Room 326
Honolulu, Hawaii 96813

DATED: Honolulu, Hawaii, August 6, 2007

RANDALL Y.K. YOUNG
Associate Counsel
Naval Facilities Engineering Command, Pacific